

**PREVENTION OF SIGNIFICANT
DETERIORATION APPLICATION
(REVISED)**

**CHERRY POINT COGENERATION PROJECT
A 720 MEGAWATT ELECTRIC GENERATING FACILITY**

Prepared for

BP West Coast Products LLC

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1 INTRODUCTION

BP West Coast Products LLC (BP) proposes to install and operate a natural-gas-fired combined-cycle combustion turbine cogeneration facility (Cherry Point Cogeneration Project) adjacent to the Cherry Point Refinery located near Blaine, Washington. When fully operational, the nominal generating capacity will be about 720 megawatts (MW) at ISO conditions.

The cogeneration facility will be designed and permitted to provide base load electric service and to operate year-round except for maintenance. Distribution of the electric power will be to the nearby transmission system with some electric power dedicated to the BP Cherry Point Refinery via existing internal transmission systems. Commercial operation could begin on or about the 2nd-1st calendar quarter of 2006.

The Project will consist of three combustion turbines (CTs), three associated heat recovery steam generators (HRSG) and one unfired steam turbine (ST). The HRSGs will be equipped with supplemental firing capability (duct burners). The Project will be operated only in combined-cycle mode. The CTs and the duct burners will be fired with natural gas. Each of the CT/HRSG combinations will have an associated stack with Best Available Control Technology (BACT) applied to control potential air emissions.

The Project will also include the installation and operation of the following:

- one diesel-driven generator approximately 1,500 kilowatt (kW) in size to supply emergency electric power to the facility for running essential facility equipment and systems when external power is not available from the grid and the CTs are not operating;
- one diesel-driven fire water pump; and,
- one multi-cell cooling tower.

The diesel engines will fire only low-sulfur distillate fuel oil with a maximum sulfur content of 0.05 percent (%).

Further discussion of Project equipment is provided in Section 2 of this document.

Operation of the Project will result in the emission of criteria pollutants such as particulate matter, oxides of nitrogen (NO_x), carbon monoxide (CO), sulfur dioxide (SO₂), volatile organic compounds (VOCs) and some toxic air pollutants (TAPs). For purposes of this analysis, all NO_x emissions are assumed to be 100 percent converted to nitrogen dioxide (NO₂) and all particulate matter is assumed to be fine particulate matter (PM₁₀).

U.S. Environmental Protection Agency (USEPA) guidance stipulates that the proposed Project will be considered as a

“fossil fuel fired steam electric plant of more than two hundred fifty (250) million British Thermal Units (mmBtu) per hour heat input”

and is one of the 28 listed sources in the Washington Administrative Code (WAC), Section 173, Chapter 400 [WAC 173-400-030(40)(e)(xxvi)]. This Project will be considered a new major source of air emissions since the projected “potential-to-emit (PTE)” annual emission rate of oxides of nitrogen (NO_x) (a regulated criteria pollutant) is expected to exceed 100 tons per year (tpy).

The Project site area is considered to be in “attainment” (currently meeting the ambient air quality standards) for all criteria pollutants. No “non-attainment” areas exist within 50 kilometers of the Project site.

Based on the Project’s PTE for NO_x and [its](#) location in an “attainment” area, the Project is subject to review under the Prevention of Significant Deterioration (PSD) regulations as presented in the Code of Federal Regulations (CFR), Title 40, Part 52, Subpart A, Section 52.21 (40 CFR 52.21) and the state of Washington Department of Ecology (Ecology) PSD permit program requirements outlined in WAC 173-400. An overview of the regulations relevant to the Project is presented in Section 3 of this document.

Meetings have been held with Ecology, the state of Washington Energy Facility Site Evaluation Council (EFSEC), the National Park Service (NPS), and the Federal Land Manager (FLM) staff regarding the Project and the PSD air quality permitting requirements. As the Project is designed to be in excess of 350 MW of electric generating capacity, EFSEC is the regulatory authority responsible for the review of the Application for Site Certification (ASC), the PSD Application and the subsequent issuance of the PSD permit. Included in the discussions with the regulatory agencies were the selection of BACT, the methodology for conducting the air quality analyses and the extent of air quality and other impact analyses required.

The cogeneration facility is designed to integrate with the BP refinery to increase the overall efficiency of electrical and steam generation. Operation of the cogeneration facility will minimize the need to obtain electricity from external generating and distribution sources and will avoid the operation of temporary natural-gas-fired turbine generators. The cogeneration facility will also provide approximately 510,000 pounds per hour (lbs/hr) of steam to the refinery, which will allow BP to shut down three older utility boilers.

The cogeneration facility will enable BP to shut down boilers and make other modifications at the refinery that [are expected to will](#) result in a net reduction in overall criteria air emissions. These emissions reductions are discussed in detail in the EFSEC ASC, however, they are largely ignored for purposes of this PSD permit application. The one exception where the refinery emissions reductions are used as part of a PSD-related evaluation is in the visibility analyses (see discussion in Section 7.5), which describes the evaluation of the

visibility impacts of the cogeneration facility alone as well as with the curtailment of the Refinery boiler operations.

Based on the results of an evaluation of Best Available Control Technology (BACT) and an air quality impact analysis, the plant will be able to operate at any load condition between 50 percent (%) and base load (100%), with or without supplemental firing (duct burners) in the HRSG; ~~and with power augmentation at any time of year~~, without causing any of the pollutant-specific significant impact levels (SILs) [WAC 173-400-113(3)] to be exceeded and without impairment to visibility.

The technical analysis information contained in this application presents significant evidence to demonstrate the following:

- PSD review is required for PM₁₀, NO_x, CO, SO₂, VOC, and sulfuric acid mist (H₂SO₄) emissions.
- BACT will be applied to control emissions. Dry low-NO_x combustors and Selective Catalytic Reduction (SCR) will be utilized in the HRSGs to reduce NO_x emissions. The combustion of clean-burning natural gas will minimize PM₁₀ and SO₂ emissions. Good combustion controls in combination with oxidation catalyst will be BACT for CO, VOCs and toxic air pollutants.
- Air quality in the proposed site area will not be adversely affected by the operation of the proposed Project. Projected ambient impacts for all criteria pollutants will be below the SILs and well below the federal and state ambient air quality standards (AAQS).
- Projected impacts of toxic emissions will not exceed any of the Ecology-specified Acceptable Source Impact Levels (ASILs) listed in WAC 173-460.
- No non-attainment areas or sensitive PSD Class I areas will be adversely impacted by Project emissions.
- Predicted impacts will be well below applicable Class I and Class II PSD increments.

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The calculation of emissions (emission inventory) is discussed in Section 4. The selection of emission control technologies (BACT) is discussed in Section 5. The methodology used to conduct the air quality impact analyses is presented in Section 6 with the air quality impact analysis results presented in Section 7.

2 PROJECT DESCRIPTION

2.1 Site Description

The BP Cherry Point Refinery and the proposed Project site are located in the 6,500-acre area zoned for Heavy Impact Industrial use in the Whatcom County Comprehensive Plan issued May 20, 1997. Surrounding this area, the land is primarily rural and agricultural with some low-density residential areas. The ~~Intaleo-Alcoa~~ Aluminum plant and the ~~Conoco-Phillips~~ Northwest Refinery are located about 6 miles south-southeast of the project site. By USEPA definition, the surrounding land is considered to be “flat or gently rolling terrain.” The ground-level elevation at the proposed project site area is approximately 1~~1520~~ feet above mean sea level (MSL). Figure 2-1 shows the location of the BP Cherry Point Refinery on a regional basis and Figure 2-2 shows the refinery and its immediate surroundings.

BP proposes to locate the cogeneration facility immediately adjacent to the Cherry Point Refinery. The specific location of the proposed power generating facility is illustrated in Figure 2-3.

Natural gas will be supplied to the site primarily through the existing refinery connections to the proprietary Ferndale Pipeline, which connects to the West Coast Energy Pipeline at the U.S./Canada border near Sumas. If additional gas is needed, it will be supplied by a third party.

2.2 Major Project Components

2.2.1 Combustion Turbines

BP proposes to install and operate up to three (3) General Electric (GE) 7FA combustion turbines (CTs) in combined-cycle mode. ~~The~~A “power block” will consist of 3 CTs and generators, 3 HRSGs and 1 steam turbine and generator. The CTs will be fueled only with natural gas. The ~~three~~ combustion turbine generators (CTGs) and the steam turbine generator (STG) will provide the electric power production.

The combustion turbine is the heart of a combined-cycle electric power generating facility. First, ambient air is drawn through an air inlet then filtered and compressed. The compressed air is then mixed with natural gas and combusted in the turbine combustor. Heat input to the turbine combustor would be approximately 1,614 million British Thermal Units per hour (mmBtu/hour) based on the lower heating value (LHV) and subject to load conditions and ambient temperature. Exhaust gas from the combustor is expelled through a power turbine that drives an electro-magnetic generator, thereby producing electricity. Exhaust gas exits the power turbine at approximately 1,100 degrees Fahrenheit (°F) and is routed to the HRSG.

Each CT unit will consist of an air compressor, a fuel combustion system, a power turbine, and a 60-hertz (Hz) generator unit. The CT generator sets will be designed to produce approximately 173 MW each of electric power at base load and 50°F ambient temperature. Actual hourly production rates will depend on operating and ambient conditions such as load, ambient air temperature and ambient relative humidity. The generation of some air emissions, as well as the CT exhaust flow characteristics, are similarly affected by the operating load and ambient air conditions.

The CTs will be designed to operate 24 hours per day every day of the year. Based on potential power requirements, operation of the CTs at loads between 50 percent and 100 percent of base load is anticipated. Operation at less than 50 percent of base load is not anticipated for significant periods of time and will be associated with CT startup or shutdown periods.

2.2.2 HRSG With Supplemental Heat Input (Duct Burners)

Since the exhaust gas exiting the CT is at a temperature significantly above the original air inlet conditions, it will be routed to an HRSG system for heat extraction (individual HRSGs for each GE 7FA CT). Each HRSG will be a three-pressure (high, intermediate, and low pressure steam generation) natural circulation design and will have the capability of supplemental firing (duct burners). The HRSG extracts heat from the CT exhaust and includes the following:

- High, intermediate and low pressure superheaters
- High, intermediate and low pressure evaporators
- High and intermediate pressure economizers
- Condensate/feedwater preheater

Exhaust gas will enter the HRSG at approximately 1,100°F and will be cooled to approximately 175°F to 195°F by the time it is routed to the HRSG exhaust stack. The extracted heat will be used to generate high-pressure steam, intermediate pressure steam, and low-pressure steam. The steam from the HRSG system will then be routed to a steam turbine.

Duct burners in the HRSG will occasionally be used to add heat, ~~(typically 89 mmBTU/hour~~ up to a maximum of ~~105600~~ mmBTU/hour,) to the HRSG when additional steam or electric power production is required. The duct burners will fire only natural gas.

2.2.3 Steam Turbine

The Project will include one condensing steam turbine (ST) designed for variable pressure operation. The high-pressure portion of the ST will receive high-pressure superheated steam from the HRSG. Similarly, the intermediate-pressure and low-pressure portions of the ST will receive intermediate- and low-pressure steam from the HRSG. The ST will be provided with a surface condenser, comprised of a shell, tubes, a water box, and a hot well. Cooling

water for the surface condenser will be supplied from a multi-cell cooling tower described below. Low pressure steam exhaust from the steam turbine will be routed to an air cooled condenser (ACC) where the steam is condensed and routed to a hot well. From the hot well, the water is pumped back into the HRSG to produce steam.

The steam turbine will drive an electro-magnetic generator (STG) that will be capable of generating approximately ~~200~~223 MW of electric power.

The ST will not generate air emissions.~~be unfired and will not be an air emission generating unit.~~

2.2.4 Diesel Generator and Diesel Firewater Pump

One diesel-driven emergency generator about 1,500 kW in size will be installed to provide support system power to critical plant instrument and lubrication systems in the event that electric power is not available from the grid. A diesel-driven firewater pump will be used to maintain firewater pressure in the event that electric power is not available or firewater pressure is inadequate. The diesel firewater pump is currently anticipated to be a John Deere Model 6081A engine (or equivalent) rated at 265 brake horsepower (bhp).

The diesel engines will be of latest design, which minimize the NO_x, CO, VOC, and PM emissions by using good combustion controls. The SO₂ emissions from the diesel engines will be minimized by using 0.05 weight percent sulfur (0.05% S) diesel fuel.

Maintenance and readiness testing checks of the diesel engines are necessary to ensure the reliability of the engines. It is anticipated that the emergency diesel generator and the firewater pump would be operated about one to two hours per week for maintenance and readiness testing purposes. However, up to a total of about 250 hours per year is evaluated in the air quality analysis. They will also operate as needed in emergency situations.

2.2.5 Cooling Cycle

Water plant cooling needs will be supplied from an induced-draft, counter-flow, multi-cell cooling tower. Fans at the top of each cooling tower cell will maintain a flow of air through the cooling tower. Circulating water pumps will move the water from the tube side of the condenser, where it picks up heat, to the top of the cooling tower. At the top of the cooling tower, the warm water is distributed onto a perforated deck. The water will fall through the perforations and will be cooled by evaporation as it falls through baffles (called "fill") to a basin at the bottom of the tower. Cool water from the cooling tower basin will be returned to the condenser via the circulating water pumps. Cooling tower components will include the basin, fans, fan deck, drift eliminators, fill, and other necessary components.

Emissions from the cooling tower are expected to consist only of PM₁₀. These emissions originate from the dissolved solids that crystallize and form airborne particulates as the cooling water vaporizes. High efficiency drift eliminators with a drift rate of 0.001 percent will be installed.

2.2.42.2.6 Emission Control Systems

The CTs will emit the criteria pollutants NO_x, CO, VOCs, SO₂, and PM₁₀, as well as a variety of other air emissions from the combustion of natural gas. Combusting only natural gas in the CTs will minimize pollutant emissions associated with proposed operations.

The CTs will be equipped with lean pre-mix dry low-NO_x combustors. These combustors have been developed to minimize the formation of NO_x. A Selective Catalytic Reduction (SCR) catalyst bed and ammonia injection grids for the control of NO_x emissions will be installed in the HRSG as well as a catalytic oxidation bed for the control of CO emissions. The oxidation catalyst will also control some of the VOC emissions. Good combustion controls and operating practices will minimize combustion pollutants such as VOC, PM₁₀ and toxic air pollutants. Sulfur dioxide will be controlled by the use of natural gas, which is inherently low in sulfur.

More in-depth discussions of the emission calculations and the emission control technologies associated with the Project are included in the Emission Inventory (Section 4) and BACT evaluation (Section 5) within this document.

2.2.6Cooling Cycle

~~2.2.6The Project would use an ACC for cooling and condensing the low pressure steam from the steam turbine. This design is more expensive than the typical evaporative water cooling systems, but it much less water intensive. The project may consider the use of evaporative cooling if an acceptable source of recycled water is developed, such as through a water reuse project.~~

2.2.62.2.7 Process Control System

An integrated microprocessor based control system will be provided for power block control, data acquisition, and data analysis. The control system will be used for startup, shutdown, monitoring and control of emissions, and for protection of personnel and equipment.

2.2.72.2.8 Facility Exhaust Stacks

The exhaust flow from each CT/HRSG combination will vent through a separate stack. The stack height for each CT/HRSG combination will be 150 feet.

2.2.82.2.9 Other Facility Structures and Equipment

The project would include the following other structures, ~~and~~ facilities and equipment:

- Steam turbine area, including foundations and support structures, for the steam turbine and its associated surface condenser

- One pressurized storage vessel for storage of anhydrous ammonia
- A warehouse area housing a workshop, a maintenance area, and offices
- Air compressor system for each unit
- Raw water storage tank
- Demineralized water storage tank
- An electrical substation and associated transformers, switches, and protective devices to step the voltage of the generated power from generator voltage to transmission line voltage.

Permanent paved on-site parking will be provided to accommodate all employees in addition to maintenance crews, visitors, and deliveries.

3 REGULATORY OVERVIEW

The USEPA and Ecology have developed air quality regulations and guidelines that require all new or modified “major sources” of air emissions to undergo a rigorous permitting process prior to commencing construction. The federal program is called New Source Review (NSR). Imbedded within the overall federal NSR program is the Prevention of Significant Deterioration (PSD) program. The provisions of the federal PSD program are contained in the Code of Federal Regulations (CFR), Title 40, Part 52, Subpart A, Section 52.21 (otherwise noted as 40 CFR 52.21). Ecology, in conjunction with Region X of the USEPA, is the regulatory authority generally responsible for review of submitted PSD applications in Washington. Since this Project is in excess of 350 MW in electric generating capacity, the facility is subject to the EFSEC regulations and EFSEC is the agency responsible for the issuance of the air permit.

The following regulatory requirements are discussed in this section:

- New Source Review (NSR)
- New Source Performance Standards (NSPS)
- Prevention of Significant Deterioration (PSD)
- National Emission Standards for Hazardous Air Pollutants (NESHAPS)
- Acid Rain Program (Title IV of the 1990 Clean Air Act Amendments [CAAA])
- Air Operating Permit Program (Title V of the 1990 CAAA)
- Risk Management Plan – (Title III of the 1990 CAAA)

In addition to the above, the facility will be subject to various Ecology and EFSEC rules and regulations. The specific provisions for obtaining a PSD permit in the state of Washington are contained in WAC 173-400. Other permitting provisions are cross-referenced in the included sections of WAC 173-400 and also will apply to the new facility. Other permitting requirements are similarly cross-referenced in the Ecology and EFSEC regulations.

3.1 New Source Review

The NSR program applies to new or modified sources that could cause a significant increase in emissions of air pollutants. The objectives of the NSR process are to demonstrate that air emissions from the new source will not significantly impact ambient air quality near the facility and that state-of-the-art emission controls will be applied.

To satisfy the general NSR requirements, the following information must be submitted:

- Notice of Construction Application Form and associated information. This application form is included at the front of the PSD application.

- PSD Applicability Analysis. The specific requirements of the PSD regulations are discussed in Section 3.3. An Ecology-required PSD Applicability Form is included at the front of this PSD application.
- "Top-down" BACT Analysis. Discussed in Section 5 of this application.
- Toxic Air Pollutant Review (WAC 173-460). Discussed in Section 3.4 of this application.
- Air Quality Modeling Analysis. Discussed in Sections 6 and 7 of this application.

3.2 Emission Standards (NSPS)

The USEPA has adopted federal emission standards applicable to various combustion sources. These emission standards are referred to as the "New Source Performance Standards (NSPS)." USEPA promulgated the NSPS for stationary CTs in 40 CFR 60, Subpart GG, dated September 1979. Ecology has adopted the federal NSPS (WAC 173-400-115). The NSPS applicable to the proposed project are summarized in Table 3-1.

A review of the federal requirements for CTs indicates that NSPS exist for NO_x and SO₂. The NO_x emission rate proposed for this project (see Section 4, Emissions Inventory) is considerably less than the calculated 103 ppm NSPS value. For SO₂, both of the NSPS values given in Table 3-1 will be met through the combustion of natural gas.

The duct burners are subject to the NSPS for steam generating units in 40 CFR 60, Subpart Db. The NO_x emission limit for the duct burners is 0.20 lb/mmBtu.

For visible emissions (opacity), the Ecology requirement is an average of 20 percent opacity in any three (3) minute period.

There are no other NSPS emissions standards applicable to this electric power generating facility.

3.3 Prevention of Significant Deterioration (PSD)

3.3.1 Attainment/Non-Attainment

The Clean Air Act (CAA) and subsequent amendments require both the USEPA and the individual states to evaluate whether areas within a state are in attainment with the AAQS. To make this assessment on a regional basis, Air Quality Control Regions (AQCRs) were established. Each AQCR is characterized into one of the following three types:

- In attainment (meeting all ambient air quality standards)

- Unclassifiable (thought to be meeting ambient air quality standards but lacking sufficient data confirmation)
- Non-attainment (measurements indicate ambient air quality standards have been or are being exceeded)

Areas are classified on a pollutant-specific basis. Unclassifiable areas are treated as being in attainment until sufficient data are collected to make a determination and the State Implementation Plan (SIP) is amended.

PSD review applies only to sources located in an attainment area or in an area designated as unclassifiable. Ecology officially designates the area around the BP Cherry Point Refinery as being in attainment for all regulated pollutants. No state of Washington designated non-attainment areas exist within 50 kilometers of the project site.

3.3.2 Applicability

For a new or modified source to be located in an “attainment” area, applicability to the PSD provisions is determined by the type of source and the quantity of air pollutants a source emits or has the “potential-to-emit (PTE)” with control equipment in operation. If a “new” source has the potential to emit more than 100 tons per year of any pollutant subject to regulation under the CAA and if it can be classified as one of the 28 source types listed in WAC 173-400-030(40)(e), then, for purposes of the federal PSD regulations, the source is considered to be a “major source” [40 CFR 52.21(b)(23)(i)]. A “new” source is also considered “major” if the “potential-to-emit” is 250 tons per year or more of any criteria pollutant, but is not one of the 28 listed sources.

The proposed cogeneration project is considered a new “major” source because the projected annual emissions of NO_x, CO and PM₁₀ exceed the 100 tpy major source threshold. Therefore, the project is subject to PSD for NO_x, CO and PM₁₀ emissions. Also, the projected (potential-to-emit) annual emissions of [VOC](#), [SO₂](#), and [H₂SO₄](#) exceed the individual significant emission rate (SER) thresholds listed in WAC 173-400-030(67). Therefore, the Project is also subject to PSD review for those pollutants.

3.3.3 General Review Requirements

Since the Project is subject to PSD review, the extent of analysis necessary to demonstrate compliance with the regulations must be individually determined for each pollutant.

According to the federal PSD and Ecology requirements, a new major source with projected annual emissions increases of any listed pollutant in excess of specified SER thresholds [WAC 173-400-030(67)] (see also Table 3-2) is required to provide the following demonstrations for each subject pollutant:

- That the appropriate emission control technologies are applied

- An evaluation of the existing ambient air quality in the area of the project site
- That the projected impact of facility emissions do not exceed pollutant-specific ambient air quality standards and/or PSD increments
- That there is no adverse impact to visibility, soils, vegetation and growth

Based on the annual emissions data presented in Section 4, the Project is subject to the above evaluations for the criteria pollutants NO_x, CO, VOCs, SO₂, PM₁₀, and sulfuric acid mist. Further review is not required for any other air emission type listed in WAC 173-400-030(67).

An emission inventory, and possibly dispersion modeling, is also required for toxic air pollutants (TAPs) that are also VOCs or PM₁₀. TAP air quality evaluations are not regulated through the PSD program but, are required by Ecology through the implementation of regulation WAC 173-460.

3.3.4 Best Available Emission Control Technology (BACT)

In the state of Washington, a BACT analysis is required for each air pollutant that is projected to have an increase in emissions (regardless of the amount of emissions). A BACT analysis is provided for CO, NO_x, VOCs, SO₂, PM₁₀, and sulfuric acid mist as well as for TAPs. A full discussion of BACT is presented in Section 5 of this application document.

3.3.5 Ambient Air Quality Impacts Analysis Requirements

The 1970 CAA mandated ambient air quality standards for certain pollutants, based upon possible identifiable effects on the public health and welfare. Applicants seeking to obtain an air permit must demonstrate, through the use of the appropriate air quality dispersion models, that the national and state Ambient Air Quality Standards (AAQS) as well as the pollutant-specific PSD increments will not be exceeded.

Criteria pollutants are those pollutants with an associated AAQS. Currently, AAQS exist for six criteria pollutants: sulfur dioxide (SO₂), fine particulate [matter](#) (PM₁₀), nitrogen dioxide (NO₂), carbon monoxide (CO), photochemical oxidants as ozone (O₃), and lead (Pb) (see Table 3-4). The total suspended particulate (TSP) standard was replaced by the PM₁₀ standard in 1987.

3.3.5.1 Significant Impact Level Analysis

Dispersion modeling for PSD applications typically first focuses on comparing the dispersion model results for the new source alone to the established significant impact levels (SILs) and determining if further modeling (PSD increment and multi-source cumulative) is required (also called identification of significant impact area). The SILs are typically 1 to 5 percent of the AAQS and are well below any levels that could lead to adverse health or welfare impacts. The SILs are presented in Table 3-5.

Used in air quality impact analyses, the SILs are a screening-level tool to determine the extent of air quality analysis required to demonstrate compliance with the AAQS and PSD increments. According to USEPA and Ecology guidance, if the modeled maximum (“worst-case”) concentrations are below the SILs, no significant impact area exists and no further modeling, taking into account other nearby increment consuming or existing sources of air emissions, is required to demonstrate compliance with the PSD increments and the AAQS. Projected (modeled) pollutant concentrations below the SILs are considered to be inconsequential relative to the PSD increments and the maintenance of the ambient air quality standards.

Based on the results of the dispersion modeling impact analyses for this project, all modeled concentrations, for all air criteria air emissions, are below their respective SILs. Therefore, further air quality modeling analyses are not required to demonstrate compliance with all ambient air quality standards and PSD increments (see discussion in Section 7).

3.3.5.2 PSD Increment and AAQS Consumption Analysis

If a SIL is projected to be exceeded for a given pollutant, then a significant impact area exists for that pollutant. The USEPA and Ecology then require an applicant to model the cumulative impacts of all “increment consuming” and “existing” sources of that pollutant at locations where predicted concentrations attributable to the proposed facility are above the SIL (within the significant impact area). The air quality analyses then change from being focused on the SILs to being focused on demonstrating compliance with PSD increments and ambient air quality standards.

~~PSD increments have been established for NO₂, PM₁₀, and SO₂ and are interpreted as the maximum allowable ground-level concentration increases of the subject pollutant. If any SIL is projected to be exceeded, then a significant impact area exists for that pollutant and the USEPA and Ecology require an applicant to model the cumulative impacts of all sources of that pollutant at locations where predicted concentrations attributable to the proposed facility are above the SILs. The air quality analyses then change from being focused on the SILs to being focused on demonstrating compliance with PSD increments and ambient air quality standards.~~

PSD increments have been established for NO₂, PM₁₀, and SO₂ and are interpreted as the maximum allowable ground-level concentration increases of the subject pollutant. PSD increment consumption is evaluated both spatially and temporally. Comparison to the PSD increments is made by summing the contributions to the predicted ground-level pollutant concentration at a particular location from all increment consuming sources (existing and new). The dispersion modeling analysis must take into account all emission sources constructed or modified after a pollutant-specific baseline date. All emission increases (and decreases) are considered to consume (or reduce) PSD increment. The amount of PSD increment available to a new source depends on the contribution of other PSD-subject sources to the total increment consumption.

Based on the results of the dispersion modeling analyses, further evaluation to demonstrate compliance with the PSD increments is not required. The PSD increments are presented in Table 3-3.

~~The dispersion modeling analysis must take into account all emission sources constructed or modified after a pollutant-specific baseline date. All emission increases (and decreases) are considered to consume (or reduce) PSD increment. The amount of PSD increment available to a new source depends on the contribution of other PSD subject sources to the total increment consumption.~~

~~Based on the results of the dispersion modeling analyses, further evaluation to demonstrate compliance with the PSD increments is not required.~~

Cumulative Modeling Analysis

Cumulative modeling for the AAQS evaluation must also include major existing sources located within the proposed source's pollutant-specific significant impact area as well as those sources which have been permitted, but which are not yet operational. Major sources located outside the proposed source's significant impact area, but which have a significant impact within the significant impact area of the proposed new source, also must be included in the cumulative modeling analysis. To account for regional background levels and other sources not included in the modeling analysis, a measured representative background concentration is added to the predicted concentration for each subject pollutant. This total concentration, per subject pollutant, is then compared to the respective ambient air quality standards to assess compliance.

Based on the results of the dispersion modeling analyses, further evaluation to demonstrate compliance with the ambient air quality standards is not required.

3.3.5.43.3.5.3 Other Impacts Analyses

PSD review and Ecology guidance require that other impacts be documented. Such other analyses include the following:

- Commercial, residential, and other growth that could occur in the area as a result of the Project
- The impairment to soils and vegetation
- The impact on PSD Class I areas including visibility, deposition and concentration
- The requirement for pre-construction ambient air quality monitoring

Two PSD Class I-designated areas are within a 100 kilometer radius of the proposed electric generating facility site, namely:

- North Cascades National Park (located approximately 80 kilometers to the east)

- Olympic National Park (approximately 100 kilometers to the southwest)

Other nearby PSD Class I areas (within 200 kilometers of the site) include the following:

- Glacier Peak Wilderness Area (approximately 115 kilometers to the southeast)
- Pasayten Wilderness Area (approximately 145 kilometers to the east)
- Alpine Lakes Wilderness Area (approximately 175 kilometers to the south-southeast)

At a meeting held at Ecology, the FLMs requested that four areas be considered in the air quality impacts analyses. At the suggestion of the FLMs, the PSD Class I air quality/visibility impacts analyses include the North Cascades National Park, the Olympic National Park, Glacier Peak Wilderness Area, and the Alpine Lakes Wilderness Area. In addition, the FLM requested that, although not a PSD Class I area, the air quality impacts at the Mount Baker Wilderness Area be evaluated.

USEPA guidelines (USEPA, October 1990) specify an exemption from preconstruction ambient air quality monitoring if projected (modeled) maximum pollutant concentrations are below the pollutant-specific *de-minimus* values presented in Table 3-6. Based on the results of the air quality impact analyses, preconstruction ambient air quality monitoring is not required for this project.

3.4 Toxic Air Pollutant Review

Ecology's toxic air pollutant regulations are contained in WAC 173-460. More than 500 toxic compounds are regulated by Ecology. Each new or modified source of toxic air pollutants (TAPs) must be evaluated under the NSR requirements.

As part of the NSR, BACT must be satisfied for TAP emissions estimated to increase as a result of the installation of the proposed project. An acceptable source impact level (ASIL) has been developed for each compound and is intended to represent the one-in-one-million (1:1,000,000) risk level. The ASIL is expressed as a concentration in micrograms per cubic meter ($\mu\text{g}/\text{m}^3$) in ambient air. To determine if a toxic compound exceeds its ASIL, air quality modeling is typically performed. Alternatively, the emission rates from the proposed new source or modification can be ~~determined on a pounds per year or pounds per hour basis and the emission rates compared~~ on a pounds per year or pounds per hour basis to the small quantity emission rate (SQER) exemptions listed in WAC 173-460. If the impact of a TAP is above an ASIL, refined dispersion modeling or a detailed health impact assessment (HIA) may be required.

In this application, each identified toxic air pollutant emission rate is compared to the SQER. If it is below the SQER, no further action is taken. If the SQER is exceeded, dispersion modeling to compare against the ASIL is performed. The results of the toxic air pollutant review are discussed in Section 7.

3.5 Other Clean Air Act Requirements

3.5.1 Hazardous Air Pollutants/NESHAPS

By USEPA Interpretive Rule (Federal Register (65 FR 21363), this type of facility is not categorically exempt from “case-by-case” MACT determinations (CAAA Sections 112[g] and 112[j]). However, as no individual HAP will have an emission rate greater than 10 tons per year (tpy) and no combination of HAPs will have a total cumulative annual emission rate of greater than 25 tpy, the facility is not subject to the MACT requirements.

No current National Emission Standards for Hazardous Air Pollutants (NESHAPs), for sources regulated under 40 CFR 61, are applicable to the proposed facility. Therefore, no current or proposed NESHAP, for sources regulated under 40 CFR Part 63, apply to the proposed facility. One new emitting source associated with the power generation project will exist that could, in the future, be subject to the NESHAPS, namely:

- Stationary Combustion Turbines

NESHAPS for this source type were due for promulgation by the USEPA by November 15, 2000 but, have not yet been promulgated. Since these rules have not been promulgated, applicability cannot be determined at this time.

3.5.2 Title IV - Acid Rain

Title IV of the Clean Air Act (the so-called “acid rain” rules) applies to utility units that commence commercial operation on or after November 15, 1990, produce electricity for sale and do not fall into one of the regulatory exemptions. These rules are contained in 40 CFR Parts 72, 75, and 76 and have been adopted into WAC 173-406. The “acid rain” rules will apply to the Project’s CTs and duct burners because these units will be utility units serving one or more generators with a nameplate capacity of greater than 25 MW.

The Title IV program consists of three primary requirements.

1. The Project will need to submit an “acid rain” permit application at least 24 months before the anticipated date for start of operations.
2. The proposed facility will be subject to requirements for continuous emissions monitoring for NO_x and ~~diluent~~diluents gas (O₂ or CO₂).
3. The proposed facility will be subject to the “acid rain” recordkeeping and reporting requirements, including the requirement to obtain and document SO₂ allowances.

As this CAAA requirement will be fulfilled independent of the PSD process, no further discussions of this issue are included in this document.

3.5.3 Title V – Air Operating Permit

The proposed facility will be subject to the federal Part 70 – Title V air operating permit program. An application must be filed within 12 months after facility operations commence. The appropriate permit documentation will be filed under separate cover and independent of the PSD process. As this CAAA requirement will be fulfilled independent of the PSD process, no further discussions of this issue are included in this document.

3.5.4 Title III – Prevention of Accidental Release

The Project will use anhydrous ammonia in the SCR system and could potentially become subject to the Prevention of Accidental Release provisions of the 1990 CAAA, Section 112(r). The handling and transport of ammonia could present environmental risks such as potential spills and subsequent evaporation of ammonia gas to the atmosphere. If the facility is determined to be subject to these provisions and prior to receiving the first shipment of ammonia at the facility, a Risk Management Plan (RMP) covering the storage, handling, and use of ammonia at the facility will be prepared and submitted to the appropriate regulatory authority. This is not part of the PSD or NOC process and would be addressed separately and prior to operation of the facility.

4 EMISSIONS INVENTORY

In accordance with direction provided by Ecology, the projected emissions of the expected pollutants (criteria and toxics) from the turbine configurations have been evaluated. Criteria pollutant emissions and operating parameter information for the GE 7FA CTs were provided by BP. This information is contained in Appendix [E-1A](#). Emission calculations for the toxic air pollutants and a summary of the criteria pollutants are provided in Appendix [E-2B](#). A description of the operating scenarios and emission calculation methodology is presented below.

4.1 Operating Scenarios

The combustion turbine is an internal combustion turbine with emissions varying with ambient temperature and load condition. Since turbine operating parameters are directly affected by the ambient temperature, the ambient temperatures of 5°F, 50°F, and 85°F are considered in the emission calculations. These temperatures are chosen to represent one winter condition (5°F), an annual average condition (50°F), and one hot summer condition (85°F). Turbine emissions are higher at lower ambient temperatures. For each of these temperatures, three load conditions are considered: 100 (base load), 75 and 50 percent load. It is conservatively assumed that the gas turbines will operate 24 hours per day, 7 days per week.

The proposed emission units for this project are as follows:

- Three (3) General Electric Frame 7FA combustion turbines (approximately 1,614 mmBtu/hour lower heating value (LHV) for each turbine at 50°F and base load conditions)-
- [One diesel-driven emergency generator, about 1,500 kW in size](#)
- [One diesel-driven firewater pump, about 265 hp in size](#)
- [One multi-cell cooling tower](#)

For each of the ambient temperatures, the following operating scenarios are considered:

- Base load on natural gas for up to 8,760 hours per year (3 CT's at 100 percent load, no duct firing)
- Base load on natural gas with duct burners operating on natural gas at a [maximum normal](#)-rate of [10589](#) mmBTU/hour LHV for up to 8,760 hours per year (3 CT's at 100 percent load, [10589](#) mmBTU/hour duct firing)

- Base load on natural gas with duct burners operating on natural gas at an average rate of 28.3 mmBTU/hour LHV for up to 8,760 hours per year (3 CT's at 100 percent load, 28.3 mmBTU/hour duct firing)
- Base load on natural gas with duct burners operating on natural gas at a ~~normal~~ maximum rate for up to ~~7,960~~4,776 hours per year, 50% load for up to 300 hours per year, and 100 hot starts and shutdowns with the remaining hours offline. ~~and at a maximum rate for up to 240 hours per year in addition to 2 turbine startup scenarios for the remainder of the year (base, maximum duct firing, economic slowdown, maintenance shutdown)~~
- A mixture of ~~p~~Part load and base load turbine operations (between 50 percent ~~load~~ and base load) could occur for up to 8,760 hours per year. Emissions for part load conditions are less than those at base load.
- An emergency diesel generator operating for testing and maintenance purposes for approximately two hours a week on any given day and up to a maximum of 250 hours per year.
- The diesel generator operating in an emergency (external power not available and turbine not operating) for any given 24-hour period. Turbines would not be operating.
- A firewater pump operating for testing and maintenance purposes for approximately of two hours a week on any given day and up to a maximum of 250 hours per year.
- The firewater pump operating in an emergency for any given 24-hour period. Turbines may be operating at the time.
- A cooling tower (PM₁₀ only) operating at peak capacity 24 hours per day, 7 days per week, 52 weeks per year.

The calculation of the emissions rates is discussed in the following sections.

4.2 Criteria Air Pollutant Emissions

4.2.1 Combustion Turbine/HRSG Emissions

The criteria air pollutant emissions estimates for the CTs are provided by the project design team~~BP~~ and are based on the emissions for a single turbine. The flue gas data for each of the ambient temperatures and load conditions are also provided. The combustion turbine manufacturer information is presented in Appendix E-1A as well as the stack emissions information provided by the project design team~~BP~~. Summaries of the calculated criteria and toxic pollutant emissions for the CTs are provided in Appendix E-2B.

The emission rates of NO_x and CO are controlled and include approximate removal efficiencies of 72 percent by the SCR and 78 percent by the oxidation catalysts. Based on information from the catalyst vendor, the VOC emission rates include a reduction of approximately 30 percent by use of the oxidation catalyst.

Sulfur dioxide emissions are calculated from the maximum expected sulfur content of the natural gas provided by BP as approximately 0.8 grains/100 standard cubic feet of natural gas for 24-hour and annual averages and 1.6 grains/100 standard cubic feet of natural gas for 1-hour and 3-hour averages. These values are suggested by Alan Newman (Newman, March 2002) of Ecology and include the addition of 0.3 grains/100 standard cubic feet for odorant.

The use of HRSGs, duct burners, and SCR and CO catalyst systems cause part of the SO_2 that is formed in the combustion process to convert to SO_3 . The conversion rate is assumed to be 20 percent of the total SO_2 as suggested by Alan Newman (Newman, March 2002) of Ecology. These assumptions are then used to estimate the formation of ammonium sulfate, which is formed due to the use of ammonia in the SCR catalyst system. For this project, it is assumed that 100 percent of the SO_3 forms ammonium sulfate. The ammonium sulfate is then added to the PM_{10} emissions estimate.

Some of the SO_3 is also expected to form sulfuric acid. Therefore, this application uses an assumption that 20 percent of the total SO_2 is converted to SO_3 and then forms sulfuric acid. Also note that sulfuric acid is not included in the PM_{10} emissions since it is regulated by itself for purposes of both PSD and WAC 173-460.

Due to the lack of actual source test information on the amount of SO_2 to SO_3 conversion and the distribution of sulfuric acid and ammonium sulfate, the emissions estimates for this project account for the same amount of sulfur several times, which results in very conservative estimates of PM_{10} and sulfuric acid emissions.

Estimates of startup and shutdown emissions were obtained from the turbine manufacturer. Startup emissions are classified into three types of startups; hot starts, warm starts, and cold starts. Hot starts are those starts that occur less than 8 hours after the turbine has been shut down. Warm starts are when the turbine is restarted after being shut down for 8 to 72 hours. Cold starts are when the turbine is restarted after being shut down for more than 72 hours.

~~Two scenarios are created to calculate the annual emissions that are expected for startup and shutdown conditions, namely:~~

- ~~□ An economic slowdown scenario that includes a day where all three turbines are operating at full load for 16 hours, two turbines are operating at 50 percent load for the remaining 8 hours while the other turbine is shut down and hot started. This scenario may occur for up to 90 days per year.~~
- ~~□ A maintenance shutdown scenario is when one turbine is shut down and cold started 22 days later. The other 2 turbines remain at full load during this period. This scenario may occur up to 66 days per year, one 22-day period for each turbine.~~

Annual emissions are calculated using a combination of full load operation with duct burners at a ~~maximum normal operating~~ maximum operating rate for ~~199 days~~ 7,960 hours per year, 50% load for 300 hours per year, 100 ~~hot start~~ hot starts and shutdowns, and the remaining hours offline. ~~with duct firing at a maximum rate for 10 days per year, economic slowdown scenario for 90 days per year and maintenance shutdown for 66 days per year. Annual emissions are also calculated assuming full operation with no startup scenarios.~~

A complete listing of the criteria pollutant hourly emissions for each operating scenario is presented in Appendix E-2B. A summary of hourly emission rates for criteria pollutants for the CT units (on a per unit basis) is shown in Table 4-1. A summary of the annual emission rates for the facility is presented in Table 4-3.

4.2.2 Auxiliary Emission Units

The emission factors for the emergency generator and the firewater pump were obtained from the manufacturers. Cooling tower PM₁₀ emissions are based on the projected operation of the cooling tower and the total dissolved and suspended solids of the make-up water and based on a drift rate of 0.001 percent. A complete listing of the hourly emissions for the criteria pollutants from the auxiliary equipment is presented in Appendix E-2B. A summary of hourly emission rates is shown in Table 4-2 and annual emission rates along with facility emissions are presented in Table 4-3.

~~4.3A complete listing of the criteria pollutant hourly emissions for each operating scenario is presented in Appendix B. A summary of hourly emission rates for criteria pollutants for the CT units (on a per unit basis) is shown in Table 4-1. Startup scenario emissions are shown in Table 4-2. A summary of the annual emission rates for the facility is presented in Table 4-3.~~

4.3 Toxic Air Pollutant Emissions

4.3.1 Combustion Turbines

As the toxic air pollutant emissions are a subset of VOC and PM₁₀ emissions, they also vary with inlet temperature and load condition. The emission factors used are either weight percentages of PM₁₀ and/or VOC or based on a fuel input. Since the toxic emissions for the CTs vary with operating condition, the emissions are presented at the highest load and lowest temperature, which generally represents worst-case conditions. It is then assumed that these conditions occur for the entire year (i.e., the annual average toxic emissions are over-estimated to obtain a conservative estimate that is then used in the modeling analysis). Full load operation with maximum duct firing is used for the hourly emissions. Full load operation with maximum duct firing for ~~10 days and normal duct firing rate for 355 days~~ are 365 days is used for annual emissions.

Emission factors for PM₁₀ and VOC toxic compounds are obtained from two different sources. Emissions factors are obtained from the speciation tables provided by the USEPA (USEPA, January 1990) and the California Air Resources Board (CARB, August 1991) for

internal combustion sources. Both agencies have published tables that speciate toxic compounds found in PM₁₀ and VOC emissions from various emission sources (both the USEPA and CARB tables are based on source testing data from the same sources).

The EPA and CARB emission factors are presented as a weight fraction of VOC or PM₁₀. Therefore, the PM₁₀ and VOC emission rates must be known in order to use the emission factors. The VOC emission factors are adjusted to a non-methane, non-ethane factor as the VOC emissions are presented on a non-methane, non-ethane basis. The PM₁₀ emission rate used in calculating the particulate toxics is for the gas turbine alone (i.e. 178 lb PM₁₀/hr). The addition of ammonium sulfates to the total PM₁₀ emission rate should not be used when calculating the particulate toxics since ammonium sulfate is not a toxic compound and would erroneously over-estimate the particulate toxics.

Emission factors from AP-42 are also used to supplement the EPA and CARB speciation tables. Section 3.1 of AP-42 is used for natural gas combustion in the CTs and Section 1.4 of AP-42 is used for natural gas combustion in the duct burners.

Sulfuric acid emissions are calculated based on the sulfur dioxide emissions as is previously discussed in Section 4.2 of this document. It is assumed that 20 percent of the total sulfur dioxide emissions are converted to sulfuric acid.

A complete list of toxic emissions for the CTs is presented in Appendix E-2B and a summary of toxic emissions for the CTs that require modeling is presented in Table 4-5.

4.3.2 Auxiliary Equipment

The VOC toxic emissions for the emergency generator and the firewater pump are calculated using emission factors from AP-42 (USEPA, October 1996). Section 3.3 of AP-42 is used for the diesel-driven firewater pump and Section 3.4 is used for the auxiliary diesel generator. These emission factors are based on the heat input to the engines. The PM toxic emissions are calculated using CARB speciation tables for diesel engines (CARB, August 1991) and are emission factors that are based on the hourly PM emission rate. Emissions estimates are presented in Appendix E-2B and Table 4-4.

5 BEST AVAILABLE CONTROL TECHNOLOGY

5.1 Introduction

Ecology requires the application of BACT for the control of each regulated pollutant emitted (in any amount) from a new source located in an attainment area. The BP CT units are subject to BACT with respect to NO_x, CO, VOC, SO₂, sulfuric acid mist (H₂SO₄), PM₁₀, and toxic air pollutants. For purposes of PSD, the SERs are exceeded for NO_x, CO, SO₂, PM₁₀ and H₂SO₄.

BACT is defined in WAC 173-400-030(12) as follows:

"An emission limitation based on the maximum degree of reduction for each air pollutant subject to regulation under the Chapter 70.94 RCW emitted from or which results from any new or modified stationary source which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment, clean fuels, or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which will exceed the emissions allowed by any applicable standard under 40 CFR Part 60 and Part 61. Emissions from any source utilizing clean fuels, or any other means, to comply with this paragraph shall not be allowed to increase above levels that would have been required under the definition of BACT in the Federal Clean Air Act as it existed prior to enactment of the Clean Air Act Amendments of 1990.

The annual average uncontrolled emissions for Case 2B (50°F, 100 percent load, and duct firing) have been used throughout the BACT analysis.

5.1.1 Previous BACT/LAER Determinations

A list of previous BACT/LAER determinations for combustion turbines is presented in Appendix [E-3C](#). The summary includes determinations for NO_x, CO, VOC, SO₂, PM₁₀, and some toxic compounds. The USEPA's RACT/BACT/LAER Clearinghouse (RBLC) keeps a listing of RBLC determinations by governmental agencies for various types of air emission sources. The determinations are available on the USEPA's Technology Transfer Network's (TTN) web page. The RBLC listings in Appendix [E-3C](#) cover information from 1990 until present and include determinations throughout the United States. It should be noted that not all BACT determinations made in the U.S. are included in the database as the completeness of the list is dependent on the submittal of recent determinations by the regulatory authorities.

5.1.2 Top-down BACT Approach

The BACT requirements are intended to ensure that a proposed facility incorporates control systems that reflect the latest techniques used in a particular industry, allow for future growth in the vicinity of the proposed facility, and do not result in the exceedance of a National Ambient Air Quality Standard (NAAQS) or other standards imposed on the state level. The BACT evaluation requires the documentation of performance levels achievable for each air pollution control technology applicable to a natural-gas-fired combustion turbine facility.

USEPA and Ecology recommend that a top-down approach be taken when evaluating available air pollution controls. The top-down BACT evaluation process is described in the USEPA document New Source Review Workshop Manual (USEPA, October 1990). The five steps involved in a top-down BACT evaluation are as follows:

- Identify all available control options with practical potential for application to the emission unit and the regulated pollutant under evaluation
- Eliminate technically infeasible options
- Rank remaining control technologies by control effectiveness
- Evaluate most effective controls and document results; if the top option is not selected as the BACT, evaluate the second most effective control option
- Select the BACT, which will be the most effective option not rejected based on energy, environmental, and economic impacts

The top down approach is used in this analysis to evaluate available pollution controls for the Project.

5.1.3 Economic Analysis

An economic analysis of each BACT alternative was performed to compare capital and annual costs (i.e., dollars per ton of pollutant removed). Capital costs include the initial cost of components intrinsic to the complete control system (reactors, piping, rotating equipment, instrumentation, monitoring equipment, and supports) and installation costs. Annual operating costs consist of the financial requirements to operate the control system on an annual basis. They include overhead, maintenance, labor, raw materials, and utility costs. Manufacturer quotes and economic calculations can be found in Appendix [E-4D](#).

5.1.3.1 Capital Costs

The capital cost estimating technique used in this analysis is based on a factored method of determining direct and indirect installation expenses. The technique is a modified version of the “Lang Method” whereby installation costs are expressed as a function of known equipment fees. This method is consistent with the latest USEPA guidance manual *OAQPS*

Control Cost Manual (USEPA, December 1995), on estimating control technology costs. The estimation factors used to calculate total capital costs are shown in Table 5-1.

Purchased equipment costs represent the delivered cost of the control equipment, the auxiliary equipment, and the instrumentation. Auxiliary equipment consists of all structural, mechanical, and electrical components required for efficient operation of the device. These include such items as fuel storage, supply piping, and exhaust gas ductwork. Auxiliary equipment costs are taken as a straight percentage of the basic equipment cost, the percentage being based on the average requirements of typical systems and their auxiliary equipment (USEPA, December 1995). In this BACT evaluation, basic equipment costs were obtained directly from the equipment vendors or from BP. Instrumentation, usually not included in the basic equipment cost, is typically 10 to 15 percent of the basic equipment cost depending on the specific application.

Direct installation costs include materials and labor for site preparation, foundations, structural steel, erection of equipment, piping, electrical wiring, painting, and facilities. Indirect installation costs include engineering and supervision of contractors, construction and field expenses, construction fees, and contingencies. Direct installation costs are expressed as a function of the purchased equipment cost, based on average installation requirements for typical systems. Indirect installation costs are designated as a percentage of the total direct cost (the purchased equipment cost plus the direct installation cost) of the system. The factors are based on the assumption that the installation is performed by an outside contractor and not by facility personnel. Other indirect costs include equipment, startup and performance testing, working capital, and interest accrued during construction.

5.1.3.2 Annualized Costs

Annualized costs are comprised of direct and indirect operating expenses. Direct costs include labor, maintenance, replacement parts, raw materials, utilities, and waste disposal. Indirect operating costs include facility overhead, taxes, insurance, general administration, and capital charges. Factors used to estimate total annualized costs are listed in Table 5-1. These annualized cost factors were obtained from the USEPA's *Control Cost Manual* (USEPA, December 1995).

Direct operating labor costs vary according to the system operating mode and operating time. Labor supervision is estimated as 15 percent of operating labor. Maintenance costs are calculated as 3 percent of the total direct cost (TDC). Replacement part costs, such as the cost to replace spent catalyst, have been included where required. Raw material and utility costs are based upon estimated annual consumption, and the unit costs are summarized in Table 5-1. In this BACT evaluation, the SCR and oxidation catalyst is assumed to be replaced every 3 years. The SCONOx catalyst is assumed to be replaced every 5 years. The cost of replacement catalyst is approximately 65 percent of the purchased equipment cost or given by the catalyst vendor. The cost of replacement catalyst is then annualized.

With the exception of overhead, indirect operating costs are calculated as a percentage of the total capital cost. The indirect capital costs are based on the capital recovery factor (CRF), defined as:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

where “i” is the annual interest rate and “n” is the equipment economic life (years). A control system’s economic life is typically 10 to 20 years (USEPA, December 1995). In this analysis, a 10 year equipment economic life of each available control technology is used. The average interest rate is assumed to be 7 percent (USEPA, December 1995). The CRF is calculated to be 0.142.

5.1.3.3 Cost-effectiveness

The cost-effectiveness of an available control technology is based on the annualized cost of the available control technology and its annual pollutant emission reduction. Cost-effectiveness is calculated by dividing the annualized cost of the available control technology by the tons of pollutant removed for that control technology each year. The bases for determining the uncontrolled emissions, controlled emissions, energy and environmental impacts, and control technology cost-effectiveness for each pollutant are summarized in the following subsections.

5.2 BACT for Nitrogen Oxides

5.2.1 Formation

NO_x is formed in two ways in the combustion processes:

- the combination of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal NO_x); and,
- the oxidation of nitrogen chemically bound in the fuel (fuel-bound NO_x).

Natural gas does not contain a significant amount of fuel-bound nitrogen. Therefore, the bulk of NO_x emissions will originate as thermal NO_x.

The rate of formation of thermal NO_x is a function of the residence time, free oxygen, and peak flame temperature. “Front-end” NO_x control techniques such as the design of the CT combustor are aimed at controlling one or more of these variables. Other control methods, such as SCR, are known as “back-end” controls and remove NO_x from the exhaust gas stream after it is formed.

5.2.2 Review of Previous BACT Determinations for NO_x

The lowest NO_x emission for CTs of similar size listed in USEPA’s RBLC (See Appendix [E-3C](#)) is 2 ppm for two ABB GT24 turbines in the PDC El Paso Milford plant in Connecticut. The Westbrook Power plant in Maine is permitted at 2.5 ppm; Tiverton Power in Rhode Island is listed at 3.5 ppm; and Blue Mountain Power, Pennsylvania is listed at

4 ppm. The Brooklyn Navy Yard is also listed at 3.5 ppm. According to the RBLC listing, these limits represent LAER.

Rumford Power and Casco Bay Energy in Maine, with CTs of similar size to those proposed for the BP Project, are both listed at 3.5 ppmvd. The Sithe/Independence Power in New York and the Wyandotte Energy facility in Michigan are listed at 4.5 ppm. According to the RBLC listing, all of these facilities are subject to BACT and PSD.

The only two similar plants listed in the RLBC that are in the Pacific Northwest are the Portland General Electric facility and Hermiston Generating in Oregon which are both listed at 4.5 ppmvd and are subject to BACT and PSD. Additional BACT determinations in the Pacific Northwest include Chehalis Generation in Washington at 3 ppm; Mint Farm Generation, [Wallula Generation](#) and Satsop Combustion Turbine Project (Phase I) in Washington and Garnet Energy in Idaho at 2.5 ppm; ~~and~~ Sumas Generation in Washington at 2 ppm. These facilities are all located in attainment areas for NO_x and, therefore, represent BACT.

The 2.5 ppm annual NO_x emission rate proposed for this Project is equal to, or even more stringent than, most recent BACT determinations for similar size CT facilities. All of the above named facilities are using Selective Catalytic Reduction (SCR) catalyst systems for control of NO_x emissions.

5.2.3 Potentially Available Control Techniques

A review of the information available at the USEPA's RBLC (See Appendix [E-3C](#)) was conducted. In addition, vendors of potentially available NO_x control techniques were contacted as well as regulatory agencies in the Pacific Northwest.

Selective Catalytic Reduction (SCR) is a control technique that has been used for more than ten years in a large number of power generation applications, mainly for large gas turbine applications. In an SCR system, ammonia is injected into the exhaust gas where it reacts with NO_x at a catalyst bed. The catalyst lowers the activation energy of the chemical reactions that take place in order to reduce ammonia and NO_x to nitrogen gas and water. SCR can provide 80 to 90 percent NO_x control when initially installed and recent projects have been permitted with NO_x emission limitations as low as 2.0 or 2.5 ppmvd stack outlet concentration.

SCONO_xTM (SCONO_x) is a new control technology that has been given consideration by USEPA and state regulatory agencies as a potential emission control technology. SCONO_x is a catalytic technique that simultaneously oxidizes CO to CO₂, NO to NO₂ and then absorbs NO₂ onto the surface of a catalyst through the use of a potassium carbonate absorber coating. VOCs are also removed by the catalyst system. This control technique does not use ammonia. According to EmeraChem (formerly Goal Line Environmental Technologies), the vendor of SCONO_x, SCONO_x can achieve NO_x emissions down to 2 ppm in some experimental applications but, this has only been demonstrated on smaller combustion

turbines (approximately 1 to 40 MW) in California and Massachusetts. To date, there have not been any SCONOX systems installed on large CT applications.

The USEPA Environmental Appeals Board and the California Energy Commission (CEC), on May 30, 2001, issued simultaneous rulings on another project that the SCONOX technology is not technically feasible for turbines of the size being considered for the proposed BP Project. In that ruling, the CEC confirmed there are several operational requirements associated with the SCONOX technology that makes it impractical as an emission control technology for 'F' Class turbines. It is further stated that all routine operating conditions were not covered in the SCONOX technology guarantee and that the guarantee would be voided if liquid water came into contact with the catalyst [*Three Mountain Power, LLC CEC Decision and EPA PSD Appeal No. 01-05* (May 31, 2001)]. This would be an impractical limitation for a catalyst bed situated downstream of boiler tubes, such as are in the HRSG. These decisions confirm the fact that the SCONOX technology is technically infeasible for a combined-cycle system of the size of the proposed facility. However, as requested by the regulatory agencies, a discussion of the SCONOX technology is included as part of this BACT determination.

XONON is a catalytic process that reduces NO_x emissions within the turbine combustion zone by lowering the combustion temperature and hence the NO_x formation. XONON has not yet been scaled up for use on larger combustion turbines and has only been demonstrated on small CTs (1.5 MW). Because XONON has not yet been developed for the GE 7FA combustor, it is not considered technically feasible for this project and is eliminated from further consideration as BACT.

Selective non-catalytic reduction (SNCR), such as Thermal DeNO_x and NO_xOUT, has also been considered for NO_x removal. SNCR does not use a catalyst and injects ammonia or urea directly in to the flue gas after the turbine. This technique requires temperatures of at least 1,600°F and up to 2,200°F. This technique can be used on boilers where the exhaust gas can reach these high temperatures but, has not been used in any CT applications where the exhaust gas maximum temperature is about 1,200°F). Therefore, SNCR is not technically feasible for this project and is eliminated from further consideration as BACT.

Some catalyst manufacturers also market non-selective catalytic reduction systems but, they do not work on sources that have high oxygen levels in the exhaust gas (such as CTs) and are, therefore, not technically feasible.

For the above reasons, only SCR and SCONOX are discussed in the following sections as add-on controls to the dry low-NO_x combustor.

5.2.4 SCONOX

EmeraChem (formerly Goal Line Environmental Technologies) developed and offers the SCONOX catalyst system for combustion turbines. A cost quote was obtained directly from EmeraChem for this project.

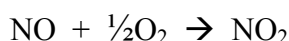
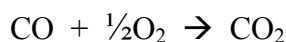
EmeraChem has not yet installed any SCONOx systems for large CTs (EmeraChem, October 2001). SCONOx has only been operated on a 34 MW facility in California since 1996 and a 5 MW facility in Massachusetts since 1999. As noted in Section 5.2.3 above, the CEC has determined that SCONOx is not technically feasible for large CT installations. The CEC decision has been upheld by the USEPA Environmental Appeals Board. Since no SCONOx systems have actually been installed and operated to-date on any large CT applications, it cannot be claimed to be a proven technology and one that is as reliable as SCR, which has been used on large combustion turbine applications for at least 10 years.

SCONOx is a highly mechanical system with dampers, seals, and louvers that all must function properly. The risk of mechanical failures is high with this type of system, especially since parts of it operates at a vacuum. If the vacuum is lost, the entire plant must be shut down, and power generation is lost. It is estimated that at least one unscheduled outage of the SCONOx system will occur annually where the turbine must be shut down. It is estimated that the outage would last for five days with a corresponding need to buy electricity from the commercial grid during this period. Therefore, the cost of a five day downtime has been added to the annualized costs (see the economic analysis).

The capital and operating costs of SCONOx are also extremely high compared to an SCR system. The capital cost and annualized costs per turbine are approximately five times higher than for SCR. Even though SCONOx is not considered technically feasible, further discussion and evaluation is provided.

5.2.4.1 Technical Analysis

Oxidation/Absorption Cycle. The SCONOx catalyst works by simultaneously oxidizing CO to CO₂, NO to NO₂, and then absorbing NO₂ onto its surface through the use of a potassium carbonate absorber coating. These reactions are shown below.



The CO₂ in the above reactions exhausts through the stack. Note that during this cycle, the potassium carbonate coating reacts with nitrogen compounds to form potassium nitrites and nitrates, which are then present on the surface of the catalyst. The SCONOx catalyst must, therefore, be regenerated on a regular basis to maintain maximum NO_x absorption.

Regeneration Cycle. The regeneration of the SCONOx catalyst is accomplished by passing a controlled mixture of regeneration gases across the surface of the catalyst in the absence of oxygen. The regeneration gases react with nitrites and nitrates to form water and elemental nitrogen. Carbon dioxide in the regeneration gas reacts with potassium nitrites and nitrates to form potassium carbonate, which is the absorber coating that was on the surface of the catalyst before the oxidation/absorption cycle began. The relevant reaction is shown below.



Water (as steam) and elemental nitrogen are exhausted through the stack instead of NO_x and potassium carbonate is once again present on the surface of the catalyst allowing the oxidation/absorption cycle to begin again.

Because the regeneration cycle must take place in an oxygen free environment, a section of catalyst undergoing regeneration must be isolated from exhaust gases. This is accomplished using a set of louvers, one upstream of the section being regenerated and one downstream. During the regeneration cycle, these louvers close and a valve opens, allowing regeneration gas into the section. Tadpole seals on the isolation louvers provide a barrier against leaks during operation. At any given time, four of five of these sections are in the oxidation/absorption cycle and one of five is in the regeneration cycle. A regeneration cycle typically is set to last for 3 to 7 minutes, so each section is in the oxidation/absorption cycle for 12 to 28 minutes. This part of the system could cause significant downtime if there is a mechanical malfunction.

Production of Regeneration Gas. The technology for producing a regeneration gas containing a dilute concentration of hydrogen from natural gas can be accomplished in several ways. For installations operating at below 450°F, the SCONOx system uses an inert gas generator for the production of hydrogen and carbon dioxide. For installations with operating temperatures greater than 450°F, the catalyst can be regenerated by introducing a small quantity of natural gas with a carrier gas, such as steam, over a steam reforming catalyst and then to the SCONOx catalyst. The reforming catalyst initiates the conversion of methane to hydrogen and the conversion is completed over the SCONOx catalyst. The reforming catalyst is placed upstream of the SCONOx catalyst in a steam reformer reactor.

Other Considerations. The SCONOx catalyst is reported to be very sensitive to sulfur in the exhaust. Sulfur must, therefore, be removed prior to the catalyst. According to EmeraChem, a sulfur filter can be used. The sulfur filter is placed in the inlet natural gas feed prior to the regeneration production skid. The sulfur filter consists of impregnated granular activated carbon that is housed in a stainless steel vessel. Spent media is discarded as a non-hazardous waste.

The SCONOx catalyst system causes a pressure drop similar to SCR catalysts. This results in a loss in power output. An OAQPS cost control factor of 0.2 percent of the megawatt output is used to calculate the annual cost of this loss in power output.

The SCONOx catalyst needs to be replaced on a regular basis. In this analysis, the catalyst is assumed to be replaced every five years. The leading layer of catalyst is washed every year whereas the remaining catalyst is washed every third year, usually in conjunction with scheduled turbine outages.

Other requirements for the SCONOx system operation are steam for catalyst regeneration, electricity, and natural gas to compensate for power losses stemming from the pressure drop across the catalyst.

5.2.4.2 Environmental Impacts

According to EmeraChem, the SCONOX system does not contribute to particulate matter since there is no ammonia to aid in the formation of ammonium salts. Since the system does not use ammonia, there are no risks of accidental spills during storage, transport and handling. However, SCR has been considered BACT for NO_x control on large CT power plants for many years and the environmental impacts of ammonia due to SCR usage have been acceptable to the USEPA and state regulatory agencies.

5.2.4.3 Economic Impacts

The cost of SCONOX compared with a low-NO_x combustor is presented below. The combustion turbines are equipped with dry low-NO_x combustors that are guaranteed to achieve 9 ppmvd NO_x during natural gas firing at loads between 50 and 100 percent. The low-NO_x combustors are currently commercially available and do not incur additional cost.

The HRSG will be equipped with low-NO_x duct burners with a NO_x emission rate of 0.08 lb/mmBtu. The low-NO_x duct burners are commercially available and do not incur additional cost. Capital costs and annualized costs incurred from installing a SCONOX system were developed using the cost determination methodology described in Section 5.1.3.

Capital costs associated with operating a SCONOX system on each of the CTs are based on cost quotations obtained from EmeraChem (Davis, September 2001). The basic equipment cost was obtained for a SCONOX catalyst system to control NO_x to 2 ppm, at least 90 percent removal of CO, and 90 percent removal of VOC at base load.

EmeraChem offers several price options, namely:

- The complete system can be purchased, which includes the mechanical equipment and the catalyst.
- The mechanical equipment can be purchased in conjunction with leasing the catalyst.
- The catalyst can be purchased by itself or leased by itself.

The latter two options allows the customer to obtain the mechanical equipment elsewhere. For this project, only the complete system purchase and the mechanical system purchase in conjunction with leasing the catalyst are evaluated.

Complete System Purchase Option. This option allows the customer to buy all the SCONOX capital equipment including the catalyst module and reactor housing, regeneration gas system, and catalyst removal system. EmeraChem has not included the cost of installation, some necessary auxiliary equipment, catalyst washing, catalyst replacement, or maintenance of the system. The basic equipment cost for the complete system purchase option is approximately \$10,148,000 per turbine. When installation costs are added, the total capital cost is \$20,348,300. The capital costs are presented in Table 5-2.

Annualized costs are also shown in Table 5-2. They include additional labor, maintenance, and annual catalyst replacement costs. Utility costs, as well as other system replacement parts, are also listed. The cost of a five-day unscheduled outage is also added when BP would have to buy electricity from the commercial grid. The actual cost would be the differential cost to produce the electricity in the cogeneration plant and the cost to buy the electricity. This is estimated to be \$10 per MWh. Spent catalyst would be returned to the vendor, who includes the catalyst disposal costs in the price of the catalyst. The total estimated annualized cost of the complete system purchase option on each CT is \$6,584,500. The SCONOx catalyst system can remove approximately ~~195,269~~ tons/year of NO_x (about 90 percent removal efficiency), resulting in a cost of ~~\$33,800,24,500~~ per ton of NO_x removed.

Mechanical Purchase/Lease Option. The lease option allows the customer to buy the capital equipment with the exception of the catalyst. The catalyst is leased and, in the leasing price, the first catalyst charge and all required catalyst replacements are included. EmeraChem has not included the costs of installation, some necessary auxiliary equipment, catalyst washing, or maintenance of the system.

The basic equipment cost for the mechanical equipment is approximately \$5,846,300 per turbine. When installation costs are added, the total capital cost is \$11,790,700. The capital costs are presented in Table 5-3. Annualized costs for the lease option are the same as the complete system purchase option except that the catalyst replacement is included in the lease price. The annualized costs are \$4,463,000 and are also shown in Table 5-3. The same amount of NO_x is removed, which results in a cost of ~~\$22,900,16,600~~ per ton NO_x removed.

Comparison of SCONOx with SCR and oxidation catalyst. Since SCONOx can remove NO_x, CO, and VOC simultaneously, the cost per total pollutant removed using SCONOx is compared to SCR in combination with oxidation catalyst. The cost for total NO_x, CO, and VOC removed by SCONOx (complete system purchase is used since SCR and oxidation catalyst is also a complete system purchase) is ~~\$18,100,15,000~~ per ton. The cost for total NO_x, CO, and VOC removed by SCR in combination with oxidation catalyst is ~~\$10,400,8,900~~ per ton as shown in Table 5-4.

Conclusion. The cost of both price options for SCONOx is significantly higher than what is considered reasonable for control of NO_x in Washington, which has typically been around \$10,000 per ton of NO_x removed (Newman, May 2002). Since SCONOx is not yet a proven technology, it cannot be considered as reliable as SCR and the cost of downtime could be even higher than what is presented. In addition, when comparing SCONOx to SCR in combination with oxidation catalyst, the cost per total NO_x, CO, and VOC removed is not reasonable. Therefore, since the economic impacts are cost prohibitive and the technology is not proven, SCONOx cannot be considered BACT for control of NO_x.

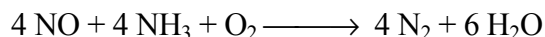
5.2.5 Selective Catalytic Reduction

The formation of NO_x from the CTs is minimized by the use of dry low-NO_x combustors. These combustors control NO_x to 9 ppmvd for the GE 7FA turbine under full load operating

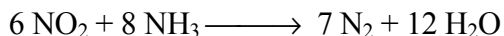
conditions and for loads down to 50 percent during natural gas firing. To achieve lower levels of NO_x, add-on control would be required such as SCONO_x or SCR. In this section, SCR is evaluated.

5.2.5.1 Technical Analysis

SCR is a process that involves post-combustion removal of NO_x from the flue gas with a catalytic reactor. In the SCR process, ammonia injected into the combustion turbine exhaust gas reacts with nitrogen oxides and oxygen in the exhaust gas to form nitrogen and water. The chemical reactions are:



and



These reactions take place on the surface of the catalyst. The function of the catalyst is to lower the activation energy of the NO_x decomposition reaction effectively. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, and design of the NH₃ injection system.

The catalyst reactor is of fixed-bed design. In this reactor design, the catalyst bed is oriented perpendicular to the flue gas flow. The reactants are transported to the active catalyst sites through a combination of diffusion and convection. In this Project, where there is an HRSG used for heat recovery, the SCR unit will likely be installed between the superheater and the high pressure evaporator coils of the HRSG.

In recent years, there have been many advances to the catalyst formulation. The narrow range of catalyst operating temperatures used to be a disadvantage. SCR systems were rarely used in high temperature exhaust applications. New materials are constantly being developed and evaluated and there are several materials available for SCR catalysts. This project would use a typical vanadium-titanium catalyst system, which has an operating temperature range of about 600 to 800°F.

Installation of a catalyst bed also causes a pressure drop of approximately 4 inches of water, which contributes to a loss in power output. An OAQPS cost control factor of 0.2 percent of the megawatt output is used to calculate the annual cost of this loss in power output.

Sulfur content of the fuel is an additional concern for systems that employ SCR. Catalyst systems promote oxidation of sulfur dioxide to sulfur trioxide (SO₃), which combines with water to form sulfuric acid or reacts with excess ammonia to form ammonium salts.

The SCR process is also subject to catalyst deactivation over time due to physical deactivation and chemical poisoning. Catalyst suppliers typically guarantee a three year catalyst life for combustion turbine applications.

In all SCR applications, there will be some unreacted ammonia emitted through the stack since the ammonia is injected in a slightly higher ratio than is stoichiometrically required. The ammonia slip design rate is a maximum of 540 ppm and is often lower in actual operation of the source.

5.2.5.2 Environmental Impacts

The potential environmental impacts associated with the use of SCR are:

- Small amounts of unreacted ammonia would be emitted to the atmosphere (ammonia slip)
- Small amounts of ammonium salts potentially could be emitted to the atmosphere

The use of SCR technology will result in ammonia emissions to the atmosphere due to unreacted ammonia leaving the SCR unit. BP proposes to operate the facility with ~~an annual average concentration of 5 ppmvd ammonia (at 15 percent O₂) and~~ maximum 24-hourly average concentration of 40-5 ppmvd (at 15 percent O₂). All of the emissions calculations and air quality evaluations are ~~conservatively~~ based on the 540 ppmvd limit.

Ammonium salts would be emitted to the atmosphere if SCR is used with sulfur-bearing fuels. The ammonium salts can be formed when sulfur trioxide reacts with ammonia to form ammonium sulfates. The potential ammonium sulfates from this project have been quantified and included in the PM₁₀ emissions and evaluated in the air quality modeling sections of the PSD application.

5.2.5.3 Economic Impacts

The cost of SCR compared with a low-NO_x combustor is presented below. The CTs will be equipped with dry low-NO_x combustors that will be guaranteed to achieve 9 ppmvd NO_x when firing natural gas at loads between 50 and 100 percent. The low-NO_x combustors are currently commercially available and do not incur additional cost. The HRSG will be equipped with low-NO_x duct burners with a NO_x emission rate of 0.08 lb/mmBtu. Capital costs and annualized costs for installing an SCR system are developed using the cost determination methodology described in Section 5.1.3.

Capital costs associated with operating an SCR system on each of the CT/HRSG systems are based on cost quotations obtained from Envirokinetics (Crites, July 2001). The overall removal efficiency is approximately 72 percent to achieve a NO_x level of 2.5 ppm. SCR capital equipment includes the catalyst, reactor, ammonia storage tanks, SCR control systems and instrumentation, and ammonia delivery system. These items represent the basic equipment, including the cost of the initial catalyst, which is estimated at \$2,291,900. When the direct and indirect installation costs are added, the total capital cost is estimated at approximately \$4,604,400 for each turbine. The capital costs are presented in Table 5-2 on a per-turbine-basis.

Annualized costs for SCR are also shown in Table 5-2. They include additional operating labor (2 hours per shift) and supervisory labor. Replacement parts include an annual catalyst

replacement cost as well as other system replacement parts. Spent catalyst would be returned to the vendor, who typically includes the catalyst disposal costs in the price of the catalyst.

Other annualized costs include ammonia at an estimated cost of \$300 per ton, an output penalty due to pressure drop across the catalyst, and indirect operating costs (overhead, taxes, insurance, capital recovery). Total estimated annualized costs of the SCR system on each CT are shown in Table 5-2. The cost, per CT, of adding an SCR system to the dry low-NO_x combustor is \$~~9,4007,600~~ per ton of NO_x removed (assuming a NO_x emission concentration of 2.5 ppmvd). The cost of \$~~9,4007,600~~ per ton of NO_x controlled is representative of BACT for NO_x control on the CTs.

5.2.6 NO_x BACT Conclusions

BACT for NO_x from the CTs and duct burners is proposed based upon the use of SCR and turbines/duct burners equipped with low-NO_x combustors. The BACT emission limitation is determined to be 2.5 ppmvd (corrected to 15 percent O₂) during steady state operations, based on an annual average. Ammonia slip associated with the SCR will be limited to a maximum 24-hour average of ~~10.5 ppmvd (corrected to 15 percent O₂) and an annual average of 5 ppmvd (corrected to 15 percent O₂) during steady state operations.~~

5.3 BACT for Carbon Monoxide

5.3.1 Formation

Carbon monoxide (CO) is formed as a result of incomplete combustion of fuel. CO is controlled by providing adequate fuel residence time and high temperature in the combustion device to ensure complete combustion. These control factors, however, also result in high emission rates of NO_x. Conversely, a low NO_x emission rate achieved through flame temperature control (by low-NO_x combustors) can result in higher levels of CO emissions. Thus, a compromise is established whereby the flame temperature reduction is set to achieve the lowest NO_x emission rate possible while keeping the CO emission rates at acceptable levels.

5.3.2 Review of Previous BACT Determinations for CO

A review of USEPA's RBLC (See Appendix ~~E-3C~~) and contacts with combustion turbine manufacturers indicate that the most common add-on control for CO is catalytic oxidation. However, since low CO emissions can be achieved by combustion control alone, most entries in the RBLC quote good combustion control as the BACT control option. The lowest CO level listed in the RBLC is the Newark Bay Cogeneration project at 1.8 ppm. The Blue Mountain Power is permitted at 3.1 ppm CO and Wyandotte Energy is permitted at 3 ppm CO. It should be noted that the Wyandotte Energy facility and Newark Bay Cogeneration must achieve their CO levels as LAER. Most other facilities list BACT as good combustion controls at CO levels between 10 and 30 ppm.

The only two similar plants listed in the RLBC that are in the Pacific Northwest are the Portland General Electric facility and Hermiston Generating in Oregon that are both listed at 15 ppm. More recent projects in the Pacific Northwest have been permitted with catalytic oxidization around 2 to 5 ppm including Mint Farm Generation, [Wallula Generation](#), and Satsop Combustion, ~~in Washington~~ and Sumas2 Generation in Washington at 2 ppm; Chehalis Generation in Washington at 3 ppm; ~~and~~ Garnet Energy in Idaho at 5 ppm. These facilities are all located in attainment areas for CO and, therefore, represent BACT.

The 2 ppm annual CO emission rate proposed for this Project is equal to, or even more stringent than, recent BACT determinations for similar size CT facilities.

5.3.3 Potentially Available CO Control Techniques

CO emissions from the CTs are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. These factors can be controlled by efficient design and good operational controls. Combustion control is the most common method to minimize CO emissions from combustion turbines.

Catalytic oxidation is technically available and has been used extensively to control CO in many power plant applications. Catalytic oxidation can also remove some VOC. Therefore, catalytic oxidation for CO control is evaluated in the following sections.

SCONOX can also remove CO by about 90 percent although its technical feasibility as a control option for large CTs is questionable at this time. Nevertheless, SCONOX is discussed below as an emission control technology for control of CO emissions.

5.3.4 Catalytic Oxidation for CO Control

The GE 7FA turbine can achieve 9 ppmvd at loads between 50 and 100 percent when firing natural gas without additional controls and will, with the implementation of a CO catalyst system, achieve an annual average CO emission rate of 2.0 ppmvd.

5.3.4.1 Technical Analysis

As with SCR catalyst technology for NO_x control, oxidation catalyst systems seek to remove pollutants from the turbine exhaust gas rather than limiting pollutant formation at the source. Unlike an SCR catalyst system, which requires the use of ammonia as a reducing agent, oxidation catalyst technology does not require the introduction of additional chemicals for the reaction to proceed. Rather, the oxidation of CO to CO₂ uses the excess air present in the turbine exhaust. The activation energy required for the reaction to proceed is lowered in the presence of the catalyst. Technical factors relating to this technology include the catalyst reactor design, optimal operating temperature, pressure loss to the system, and catalyst life.

Catalytic oxidation reactors have been applied successfully to various commercial sources. In combustion turbine applications, the catalyst bed is oriented perpendicular to the gas flow and is usually installed vertically in the HRSG.

Oxidation catalyst reactors operate in a relatively narrow temperature range. Optimum operating temperatures for these systems generally fall into the range of 700 to 1,100°F. At lower temperatures, CO conversion efficiency falls off rapidly. Above 1,200°F, catalyst sintering may occur, causing permanent damage to the catalyst.

The installation of a catalyst bed causes a pressure drop of approximately 1.5 inches of water, which contributes to a slight loss in power output. An OAQPS cost control factor of 0.2 percent of the megawatt output is used to calculate the annual cost of this loss in power output.

Catalyst systems are subject to loss of activity over time due to physical deactivation and chemical poisoning. Catalyst suppliers typically guarantee a three-year catalyst life for combustion turbine applications.

5.3.4.2 Economic Analysis

Capital and annual costs associated with installation of an oxidation catalyst system on each GE 7FA CT/HRSG system were obtained from Envirokinetics (Crites, July 2001). The overall removal efficiency is approximately 78 percent to achieve a CO level of 2.0 ppm. Oxidation catalyst capital equipment includes the catalyst, reactor, control systems, and instrumentation. These items represent the basic equipment, including the cost of the initial catalyst, which is estimated at \$2,162,900. When the direct and indirect installation costs are added, the total capital cost is estimated at approximately \$4,338,100 for each turbine. The capital costs are presented in Table 5-6 on a per-turbine basis.

Annual operating costs, also summarized in Table 5-6, include operating labor (two hours/shift), routine inspection and maintenance, spent catalyst replacement, and lost cycle efficiency due to the increased backpressure.

The cost is \$~~12,800~~^{11,300} per ton CO removed. This cost is normally not considered reasonable for CO BACT in Washington, which has typically been around \$5,000 per ton of CO removed (Newman, May 2002). However, BP is proposing to voluntarily apply more stringent CO emission controls and each CT/HRSG system will be equipped with an oxidation catalyst to control CO emissions to an annual average of 2 ppmvd (at 15 percent O₂).

5.3.5 SCONOX

A technical analysis of SCONOX is presented in Section 5.2.5 of the NO_x BACT. See that section for a discussion of the SCONOX technical, environmental and economic impacts.

Tables 5-3 and 5-4 show the cost of CO removal for SCONOX. SCONOX results in a cost of \$42,700 per ton CO removed for the complete system purchase option and \$28,900 for the

mechanical purchase/catalyst lease option. This is not a reasonable cost for CO removal and is, therefore, rejected as BACT. As was described in the above section on CO BACT, the use of oxidation catalyst is BACT for CO emissions for the CT/HRSG systems. The use of SCONox is rejected as BACT for this facility as SCONox has not been demonstrated as a feasible option for this size CT.

5.3.6 CO BACT Conclusions

The use of an oxidation catalyst for control of CO from the CTs and duct burners is proposed. The CO emission rate is proposed to be 2.0 ppmvd (corrected to 15 percent O₂) during steady state operations, based on an annual average. For operational flexibility, an emission rate of 5.0 ppmvd (1-hr average corrected to 15 percent O₂) is also proposed.

5.4 BACT for Volatile Organic Compounds

5.4.1 Formation

Unburned hydrocarbons (UHC) are emitted from CTs as a result of incomplete combustion of fuel. The volatile components of the unburned hydrocarbons are organic compounds that participate in atmospheric photochemical reactions. This excludes methane, ethane, CFCs, and other compounds that have negligible photochemical reactivity. Control of VOCs is accomplished by providing adequate fuel residence time and high temperature in the combustion device to ensure complete combustion and/or back-end control techniques such as catalytic oxidation to control VOCs after they are formed.

5.4.2 Potentially Available VOC Control Techniques

The most stringent VOC control level for large combustion turbines firing natural gas has been achieved using catalytic oxidation. Three turbine projects are listed in the RBLC as using oxidation catalyst and the permitted level is 2 to 4 ppm VOC. All the other combustion turbines listed in the RBLC list combustion control as BACT. The installation of catalyst system for the control of CO emissions is also an emission control measure for a variety of VOCs.

The use of combustion controls is the most common control for minimizing VOC emissions from combustion turbines. Good combustion control indicates that VOC emissions are minimized by optimizing fuel residence time, excess air, and combustion temperature to assure complete combustion of the fuel.

Since both catalytic oxidation and combustion controls are technically and commercially feasible for the turbines, these controls are evaluated in terms of VOC BACT.

5.4.3 Catalytic Oxidation for VOC Control

The same technical factors that apply to the use of oxidation catalyst technology for control of CO emissions (narrow operating range, loss of catalyst activity over time, and system pressure losses) apply to the use of this technology for VOC control. Further discussion of these factors can be found in Section 5.3.4.

According to the CO oxidation catalyst vendor, an added benefit of the CO oxidation catalyst is that it can remove up to 30 percent of the methane, ethane, and propane. The CO oxidation catalyst could also remove up to 70 percent of smaller VOC compounds. This analysis conservatively assumes that the CO oxidation catalyst removes up to 30 percent of the VOC emissions from the CT/HRSG systems.

If an additional oxidation catalyst were to be installed, one that was designed specifically for VOC control, it would be at least as expensive as a CO oxidation catalyst. With the small amount of VOC emitted from each CT/HRSG system, the cost would be approximately \$100,000 per ton VOC removed. This analysis does not include an economic evaluation for such a catalyst since it is not an economically viable option. Therefore, a separate VOC oxidation catalyst is not considered further and the oxidation catalyst alternative addresses a dual CO/VOC catalyst.

The use of combustion controls as the second most stringent alternative is evaluated below.

5.4.4 Combustion Controls

Combustion controls are aimed at controlling the parameters that affect the formation of VOC. Optimizing the excess air, flame temperature, residence time at flame temperature, combustion zone design, and turbulence will result in reduced VOC formation. This is a proven technique and is listed as BACT for the majority of combustion turbines in the RBLC.

Combustion controls have no additional environmental impacts, do not result in increased emissions of other pollutants, and incur no additional cost for the turbines. By operating the turbines properly to ensure good combustion, the VOC emissions from the combustion turbines will be a maximum of 3 ppm at all considered loads while firing natural gas without duct firing. Therefore, combustion controls in combination with the CO oxidation catalyst are determined as BACT for VOC emissions from the CT/HRSG systems.

5.4.5 SCONOX

A technical analysis of SCONOX was presented in Section 5.2.5 of the NO_x BACT. See that section for a discussion of SCONOX technical, environmental and economic impacts.

Tables 5-3 and 5-4 show the costs associated with SCONOX. Compared to catalytic oxidation and combustion controls, SCONOX would be extremely expensive for VOC control alone and is, therefore, not an economically feasible option. Neither SCONOX

catalyst, nor a specific VOC oxidation catalyst would be cost-effective for VOC removal. As was described in the above sections, combustion controls in combination with the CO oxidation catalyst are BACT for VOC emissions from the CT/HRSG systems.

5.4.6 VOC BACT Conclusions

BACT for VOC from the CTs and duct burners is proposed based upon the use of oxidation catalysts. The BACT emission limitation is determined to be 3.06.9 lbs/hour during steady state operations, based on a 24-hour averaging basis.

5.5 BACT for Particulate Matter

5.5.1 Formation

Particulate emissions from natural gas combustion sources consist of ash from the fuel and particulate of carbon and hydrocarbons resulting from incomplete combustion. Therefore, units firing fuels with low ash contents and high combustion efficiency exhibit correspondingly low particulate emissions.

5.5.2 Available PM₁₀ Control Techniques

When the New Source Performance Standard (NSPS) for Stationary Combustion turbines (40 CFR 60, Subpart GG) was promulgated in 1979, the USEPA recognized that particulate emissions from stationary CTs are minimal, that particulate control devices typically are not installed on CTs, and acknowledged that the cost of installing a particulate control device is prohibitive. Performance standards for particulate control of stationary CTs are, therefore, neither proposed nor promulgated.

According to General Electric (Davie, February 2000), the CT manufacturer, the guaranteed particulate matter emission rate for a natural-gas-fired turbine is based on USEPA Method 5 measurements. However, these measurements produce an anomalous PM₁₀ number because the actual emissions are so low. The PM₁₀ emissions that are presented are a product of the test method rather than actual PM₁₀ emissions. This is a fairly typical result when trying to measure very low emissions concentrations (e.g., ammonia slip also suffers from anomalous measurement methods).

The most stringent “front-end” particulate control method demonstrated for combustion turbines is the use of low-ash fuel and/or low-sulfur fuel and controlled combustion to minimize particulate formation. The RBLC lists some form of combustion control and/or low ash type fuel as the control method for particulate emissions.

Typical particulate control devices such as electrostatic precipitators (ESPs) and baghouse filters are not suitable for use with CTs due to both the extremely low particulate emission concentration and the physical characteristics of the particles. For ESPs, which operate on

the principle of charge migration, the low particulate concentration would prevent significant charge buildup on particles, resulting in low migration of particles to the collecting plates.

ESP and baghouse filter vendors who were contacted indicated that they usually do not quote either of these units for natural-gas-fired CT applications. They stated that such sources typically meet emission standards "without controls." For these turbines, the peak particulate emission concentration is on the order of 0.001 to 0.003 grains per standard cubic foot (gr/scf) during natural gas firing, which approaches concentrations that vendors are striving to achieve for particulate control in other applications (such as oil-fired or other fossil-fuel-fired boilers). The use of an ESP and/or baghouse filter is considered technically infeasible and not representative of BACT.

5.5.3 Cooling Tower

The cooling tower will be equipped with drift eliminators, which are listed in the RBLC as BACT for cooling towers. Therefore, the use of drift eliminators will satisfy BACT for the cooling tower.

5.5.35.5.4 PM₁₀ BACT Conclusions

Given the lack of feasible alternatives, the use of low ash and low-sulfur fuel such as natural gas, and good combustion control can be concluded to represent BACT for PM₁₀ control for the proposed CTs. The combination of low ash fuels and good combustion control is listed as the BACT for the majority of CTs listed in the RBLC.

5.6 BACT for Sulfur Dioxide and Sulfuric Acid Mist

5.6.1 Formation

Sulfur dioxide (SO₂) is formed exclusively by the oxidation of the sulfur present in fuel. The emission rate of SO₂ is a function of combustion efficiency of the source and the sulfur content of the fuel since virtually all fuel-bound sulfur is converted to SO₂. Some of the SO₂ may be converted to SO₃, which in turn can form H₂SO₄ (sulfuric acid mist).

Sulfuric acid mist is included in this BACT analysis. Sulfuric acid mist is most often controlled by wet scrubbers for other sources high in sulfur (e.g., such as coal-fired power plants). Since a wet scrubber is evaluated for SO₂ control, it can also be used for H₂SO₄ control.

5.6.2 Available Control Techniques

The most stringent "front-end" SO₂ control method demonstrated for combustion sources is the use of low-sulfur fuel, such as natural gas. "Back-end" controls, such as wet or dry

scrubbers, are generally not applied to combustion turbines that combust low sulfur fuels due to the very low SO₂ emissions and the high cost of a scrubber. The RBLC does not list any add-on controls as BACT for combustion turbine combined-cycle plants, including those with duct burners. Wet and dry scrubbing has been listed in the RBLC as BACT for sources high in SO₂ emissions. Scrubbing would be technically feasible as SO₂ control although the low SO₂ emissions and high flue gas flow rate would require an expensive scrubber. According to scrubber manufacturers contacted, a conservative estimate of control efficiency is 90 percent with an upper-bound estimate of 99 percent control. Wet scrubbing is considerably cheaper than dry scrubbing; therefore, an economic analysis is provided for wet scrubbing for SO₂ control. The use of low-sulfur fuel, such as natural gas, was evaluated as the second most stringent control option.

5.6.3 Economic Analysis of Wet Scrubber for SO₂ and H₂SO₄

Basic equipment costs associated with installing a wet scrubber on the combustion turbine/HRSG system were obtained from a scrubber manufacturer (Interel, July 1994), scaled to the size of the CT/HRSG system flue gas flow rate. The basic equipment cost is an average of \$5.30 per cubic feet per minute (cfm) of flue gas; the original cost scaled up to account for inflation. The CT/HRSG system has an average potential flue gas flow rate of 1,000,000 actual cfm (acfm) out of the stack, resulting in a basic equipment cost of \$5,300,000. The total capital cost of a wet scrubber on one CT/HRSG system is estimated at \$14.8 million. The capital and annual costs are shown in Table 5-7.

Annual operating costs include operating labor (one hour per shift), routine inspection and maintenance, utilities, soda ash for pH control, wastewater treatment, and indirect operating costs. Estimated annual costs total \$5.8 million. The control efficiency of the wet scrubber is estimated at 99 percent. The total amount of SO₂ and H₂SO₄ removed is estimated to be ~~19,553.5~~ tons per year. This technology results in a cost of ~~\$297,100~~~~108,400~~ per ton of total SO₂ and H₂SO₄ removed. Therefore, a wet scrubber is not considered as BACT for the CT/HRSG systems.

5.6.4 Use of Low-Sulfur Fuel

The next most stringent control is the use of low-sulfur fuel such as natural gas. The natural gas is expected to have a maximum sulfur content of 1.6 grains per 100 standard cubic feet (scf) of gas and an average sulfur content of no more than 0.8 grains per 100 scf.

5.6.5 SO₂ and H₂SO₄ BACT Conclusions

The use of low sulfur fuel is listed as BACT for the CTs identified in the RBLC search. Therefore, the use of low-sulfur fuel is BACT for the CT/HRSG systems.

5.7 BACT for Auxiliary Equipment

The auxiliary equipment proposed for the Project is:

- One diesel-driven emergency generator, about 1,500 kW in size
- One diesel-driven firewater pump, about 265 bhp in size

These sources will have very low utilization throughout the year. The emergency generator will only be used to operate critical plant systems during periods when external electric power is not available. The firewater pump is available for use in the case of a fire.

BACT for the auxiliary equipment (diesel-fired engines) is good combustion control and low sulfur fuel as well as low annual usage with a limit of up to 250 hours per year for maintenance operation.

5.7.5.8 BACT for Toxic Air Pollutants

The toxic emissions from the facility are a subset of the PM₁₀ and VOC emissions. As discussed in Section 5.4 and 5.5, add-on controls are not generally required for PM₁₀ and VOC emissions from natural-gas-fired CT facilities. Therefore, the same controls that are considered for PM₁₀ and VOC emissions are considered for toxic emissions.

Baghouses and electrostatic precipitators (ESPs) are frequently used to control PM₁₀ emissions for non-natural gas burning facilities. However, the sources that use these controls are typically large emitters of PM₁₀, such as pulp and paper mills, coal-fired boilers, cement plants, and aluminum plants. Baghouses and ESPs were determined technically infeasible for PM₁₀ control on natural-gas-fired turbines as the PM₁₀ emissions are so low that neither baghouses nor ESPs can efficiently remove PM₁₀. In addition, the cost of a baghouse or ESP would be excessive due to the high flue gas flow rate. Control equipment is often sized based on flue gas flow rate, which can result in very high costs for sources with high flue gas flow rates.

VOC emissions can often be controlled by catalytic oxidation, regenerative thermal oxidation, or carbon adsorption. However, the VOC emission concentration must be much higher than what is available for the CT for regenerative thermal oxidation or carbon adsorption to be technically feasible. Sources that would use these types of controls are wood products facilities such as fiberboard, plywood, and oriented strandboard manufacturing, fiberglass manufacturing, and other organic chemical manufacturing plants.

Catalytic oxidation is technically feasible as was discussed for VOC control but a specific VOC oxidation catalyst would be cost-prohibitive since the VOC emissions are so low. The toxic portion of the VOCs is even lower, making the cost unreasonable for catalytic oxidation alone to be considered BACT for toxics. However, the CO oxidation catalyst can achieve approximately 30 percent reduction of VOC in addition to reducing CO. Therefore, a 30 percent reduction in the toxic VOCs is included in their emissions estimate.

BACT for the auxiliary equipment (diesel-fired engines) is combustion control and low sulfur fuel as well as low annual usage with a limit of up to 250 hours per year for maintenance operation.

5.7.15.8.1 TAP BACT Conclusions

Based on the above discussion on technical feasibility and cost of control, a top-down BACT analysis is not provided as it would show the same results as the BACT for PM₁₀ and VOC. The control of toxics will, therefore, be the same as for PM₁₀ and VOC; good combustion control in combination with the CO oxidation catalyst, and use of low-ash/low-sulfur fuel.

5.8.5.9 Summary of BACT

A summary of technologies determined to be representative of BACT is provided below. A table identifying each pollutant and summarizing the corresponding BACT as well as the cost per ton of pollutant removed is presented as Table 5-8. The requested BACT limits for the Project are listed in Table 5-9.

5.8.15.9.1 Nitrogen Oxides

The CTs will be equipped with dry low-NO_x combustors for the reduction of NO_x formation. The turbines will be able to achieve 9 ppmvd without add-on controls at all considered loads. With the application of SCR, the NO_x emissions will be controlled to 2.5 ppmvd annual average at 15 percent O₂.

SCONOX was also evaluated for control of NO_x. It has a similar capacity for NO_x removal as SCR, but at a considerably higher cost. SCONOX was eliminated as BACT since it is not technically feasible and due to the high capital cost and excessive cost per ton of pollutant removal.

5.8.25.9.2 Carbon Monoxide

Catalytic oxidation is the most stringent control considered for reducing CO emissions to 2.0 ppmvd on an annual average basis at 15 percent O₂.

SCONOX was also evaluated for control of CO. It has the same capacity for CO removal but at a considerably higher cost. SCONOX was eliminated as BACT due to high capital cost and excessive cost per ton of pollutant removal.

5.8.35.9.3 Volatile Organic Compounds

The installation of a specific VOC oxidation catalyst is technically feasible. However, the economic impacts would be excessive. Therefore, the oxidation catalyst, strictly for the

control of VOC emissions, is rejected as BACT. VOC emissions will be reduced by approximately 30 percent with the application of the CO oxidation catalyst.

SCONOX was also evaluated for control of VOC. It has the same capacity for VOC removal as oxidation catalyst but at a considerably higher cost. SCONOX was eliminated as BACT due to the excessive capital and annualized costs.

Combustion will be optimized by controlling the parameters that affect VOC formation. These factors include oxygen, flame temperature, residence time, combustion zone design, and turbulence. This is consistent with the majority of gas-fired turbines in the RBLC. Combustion control, in combination with the CO oxidation catalyst, is determined as BACT for VOC emissions for the Project.

5.8.45.9.4 Particulate Matter

Particulate emissions from the CTs will consist of carbon and hydrocarbons (ash) resulting from incomplete combustion, and ammonium sulfate particulate. Baghouses and ESPs are considered technically infeasible as control for particulate from the combustion turbines. The most stringent particulate control method demonstrated for a combustion turbine is the use of low ash, low sulfur fuel such as natural gas, and efficient combustion design. This alternative is concluded to represent BACT for control of particulate from the CTs.

5.8.55.9.5 Sulfur Dioxide and Sulfuric Acid Mist

Sulfur dioxide and sulfuric acid mist emissions are directly proportional to the amount of sulfur in the fuel burned. The most stringent control demonstrated for SO₂ and H₂SO₄ emissions is the use of low-sulfur fuel such as natural gas. Back-end controls such as a wet scrubber would result in a cost of ~~\$297,100~~\$108,400 per ton SO₂ and H₂SO₄ removed. Therefore, BACT for SO₂ and H₂SO₄ emissions from the Project is the use of a low-sulfur fuel.

5.8.65.9.6 Toxic Air Pollutants

The toxic emissions from the facility are a subset of the PM₁₀ and VOC emissions. Therefore, the same controls that would be considered for PM₁₀ and VOC emissions are considered for toxic emissions.

Baghouses and ESPs are determined technically infeasible for PM₁₀ control on CTs as the PM₁₀ emissions are so low that neither baghouses nor ESPs can remove PM₁₀ in an efficient manner. In addition, the cost of a baghouse or ESP is excessive due to the high exhaust flow rates.

Catalytic oxidation is technically feasible for removal of VOC but it is very cost-prohibitive since the VOC emissions are so low. The toxic portion of the VOCs is even lower, making

the cost unreasonable for catalytic oxidation for VOCs alone to be considered BACT for toxics.

The BACT for toxics will, therefore, be the same as for PM₁₀ and VOC; good combustion control in combination with the CO oxidation catalyst, and use of low-ash/low-sulfur fuel.

6 AIR QUALITY MODELING METHODOLOGY

The methodologies and protocols used in the air quality impact analysis follow USEPA Guidelines and the requirements of Ecology and the Federal Land Manager (FLM). Dispersion modeling is used to simulate the projected impact of the facility's emissions on local and regional air quality levels. The modeling protocols were submitted to EFSEC on October 29, 2001, copies of which are included in Appendix [E-5E](#).

6.1 Required Analyses

The PSD review in this application consists of the following analyses:

- A Significant Impact Levels (SILs) analysis of pollutant concentrations in Class I and Class II areas,
- A comparison of toxic air pollutant (TAP) concentrations with acceptable source impact levels (ASILs) in Class II areas, and
- A Class I area air quality related value (AQRV) analysis including an analysis of visibility and deposition.

These analyses are discussed in the following sections.

6.1.1 Significant Impact Levels Analysis

A PSD permit application is required to demonstrate, through air dispersion modeling, that the emissions increase from the proposed new facility will not cause or contribute significantly to any violations of allowable PSD increments within the Class I or Class II areas and will not cause a violation of ambient air quality standards (AAQS). SILs are established to determine an impact concentration which, when a facility's impacts are less than this level, will show that the maintenance of the PSD increments and AAQS are not threatened. If a facility's impacts are less than the SILs, additional analyses such as a PSD increment consumption analysis and multi-source, or cumulative, modeling analyses are not required to demonstrate compliance with PSD increments or the AAQS. The SILs for Class I and Class II areas are shown in Table 3-5.

6.1.2 Toxic Air Pollutants analysis

An analysis was conducted to evaluate the impact of potential toxic air pollutants (TAPs) using the guidance provided in WAC 173-460. Only toxic air pollutants with emission rates in excess of the small quantity emission rates listed in WAC 173-460-080(2)(e) were

modeled with the exception of those TAPs that have Acceptable Source Impact Levels (ASILs) less than 0.001 micrograms per cubic meter ($\mu\text{g}/\text{m}^3$). Those TAPs are required to be modeled regardless of emission rate. Modeled impacts are compared to the ASILs. The small quantity emissions levels and ASILs are shown in Table 4-5. The emissions of ammonia from the SCR system were also modeled as required by WAC 173-460.

6.1.3 Class I Area AQRV Analyses

Federal Class I Areas are places of special national or regional value from a natural, scenic, recreational, or historic perspective. These areas were established as part of the PSD regulations included in the 1977 Clean Air Act Amendments. Federal Class I Areas are afforded the highest degree of protection among the types of areas classified under the PSD regulations.

It is the responsibility of the FLMs to identify AQRVs in each of the Class I Areas that may be affected by air pollution. AQRV indicators typically identified by the FLMs include visibility degradation and acidic deposition, both of which are analyzed in this application.

For the visibility analysis, the FLMs have established a significance level of 5 percent change in light extinction over background levels using 24-hour average impacts from the project to evaluate potential project impacts. Visibility results above this level may be acceptable to the FLMs with consideration of the number of days above the 5 percent criteria and the amount above 5 percent. Background extinction coefficients used in the postprocessor CalPost were obtained from the FLAG Phase I Report. These are 0.6 Mm^{-1} for hygroscopic components and 4.5 Mm^{-1} for non-hygroscopic components for all Class I areas evaluated.

Soils and aquatic resources in Class I areas are potentially influenced by nitrogen and sulfur deposition. Nitrogen and sulfur deposition occur through both wet and dry processes. A significance level of 5 grams per hectare per year (g/ha/yr) for both sulfur and nitrogen deposition was used.

6.2 Surrounding Terrain

The base elevation at the proposed project site is about 11520 feet above mean sea level (MSL). By USEPA definition, the terrain near the project site can be classified as “simple terrain” and is essentially “flat or gently rolling.” The highest elevation within 15 kilometers of the project site is 463 feet, approximately 3483 feet above ground-level elevation at the site, which indicates that “complex” terrain would have to be included in the dispersion modeling.

6.3 ISCST3-Prime Modeling

Typically, for receptor locations that are less than 50 kilometers from a source, steady-state Gaussian dispersion models are used to determine the modeled impacts. The ~~approved~~ appropriate dispersion model for use in this air quality analysis for the Class II SIL analysis

and the TAPs analysis is the USEPA-approved Industrial Source Complex - Short Term, Version 3 (ISCST3) dispersion model as specified in USEPA's *Guideline On Air Quality Models* (Guidelines) (USEPA 2000) and as discussed with Ecology personnel in the project meetings.

AirPermits.com utilizes [the ISC-Prime dispersion model, which is the most recent a variant version of the ISCST3 dispersion model and incorporates updated building-wake \(downwash\) calculations provided by Bowman Environmental Engineering \(BEE\)](#). The [suite of models, provided by version-Bowman Environmental Engineering \(BEE\), provided by BEE](#) is called BEEST (Version 8.9349) and includes the executable versions of the both the current ISCST3 model and its variant, the ISC-Prime model (BEE Version 03002) and is based on the ISCST3 model, Version 00101. The model execution options, averaging periods, sources and emissions information, receptors and terrain, buildings and structures, and meteorology inputs of the ISC-Prime dispersion model are identical to those of the ISCST3 dispersion model. Ecology has indicated that the ISC-Prime model is an approved model for use in the BP modeling analyses (Bowman, 2003).

6.3.1 **ISCST3-Prime Model Options**

USEPA's Guidelines (USEPA 2000) lists the ISCST3 model as a preferred model for evaluating simple and complex terrain impacts within a 50 kilometer radius of the project site. Regulatory agency guidance mandates that, when performing modeling for regulatory purposes, certain options in the ISCST3 model be employed. [The guidance requirements are also being applied to the ISC-Prime model.](#) The required ISC-PrimeST3 input options are as follows and were used in the modeling analyses conducted for this project:

- Final plume rise
- Stack tip downwash
- Buoyancy induced dispersion
- Default wind profile exponents
- Default temperature gradients
- Calm period policy

Based on the land use classification procedure of Auer (1978), land use in the region surrounding the project site is greater than 50 percent rural. Therefore, rural dispersion coefficients were used in the modeling.

If modeled impacts exceed the pollutant-specific SIL, then the USEPA and the Ecology guidelines require more detailed (refined) dispersion modeling. This more detailed cumulative source modeling must include emissions for other existing sources and for other nearby sources that have been permitted, but are not yet operational. The purpose of cumulative source modeling is to evaluate the combined effect of the proposed facility, the other contributing sources, and the existing ambient (background) levels on regional attainment of the PSD increments and the Ambient Air Quality Standards (AAQS). However, as will be shown in Section 7, all maximum predicted impacts that would result from operation of the proposed facility are below the pollutant-specific SILs. Thus,

cumulative source modeling is not required to demonstrate compliance with the ambient air quality standards and PSD increments. The potential criteria pollutant emissions will have a negligible effect on the maintenance of the public health and welfare.

6.3.2 Buildings and Other Structures (Aerodynamic Downwash)

Regulatory agency guidelines require that the potential for building-induced aerodynamic downwash to affect the plume dispersion from the proposed stacks be considered in the modeling. The USEPA has established good engineering practice (GEP) stack height guidelines (*Guideline for Determination of Good Engineering Practice Stack Height* [USEPA, 1985], Stack Height Regulations [40 CFR 51], and current Model Clearinghouse guidance) to be used to determine the necessity for including aerodynamic downwash in the modeling analysis. The GEP formula stack height is defined as follows:

$$H_G = H_B + 1.5L$$

where: H_G = the GEP stack height
 H_B = the height of the nearby structure
 L = the lesser dimension (height or projected width) of the nearby structure

For a structure with a projected width greater than its height (i.e., a squat structure) the formula reduces to:

$$H_G = 2.5H_B$$

The facility site plan provided by BP (see Figure 2-3) was used to determine the horizontal ~~and vertical~~ dimensions of facility buildings and other obstacles near the stacks. [The height of all buildings and structures used in the dispersion modeling analyses was obtained in discussions with BP.](#)

Both the height and width of the nearby structures to be used in calculating the appropriate GEP stack height were determined by projecting the maximum crosswind dimension of the structures onto a plane perpendicular to the direction of the wind. If a stack is within five structure heights or widths, whichever is less, downwind from the closest edge of a structure, the stack is considered to be in the sphere of influence of the structure, and aerodynamic downwash must be considered in the modeling analyses. In the case where a stack is not influenced by nearby structures, the maximum stack height allowed in dispersion modeling is 65 meters (213 feet).

Aerodynamic downwash was included in the modeling analyses through the use of the USEPA-approved Building Profile Input Program (BPIP) software. The BPIP software is integrated as part of the BEEST software package and the direction-specific building heights and widths were used in the ISC-~~PrimeST3~~ model. BPIP outputs were also input into the CalPuff model. Buildings and other structures are identified on the site plan (See Figure 2-3). The stack and building dimensions are shown in Table 6-1.

6.3.3 ISC-~~PrimeST3~~ Meteorological Data

Actual hourly meteorological data representative of the project site are available from the BP on-site meteorological measurements program. The BP meteorological measurements program is operated to collect PSD-grade data from a variety of meteorological sensors. Quarterly data reports and quarterly audit reports are available. The hourly meteorological data for the 1995, 1996, 1998, 1999 and 2000 calendar years was processed into a format suitable for use in the ISC-~~PrimeST3~~ and CalPuff dispersion models using the USEPA-approved MPRM meteorological preprocessor. Data for calendar year 1997 were excluded due to an abundance of missing on-site data and the difficulty of locating other ~~suitable~~~~needed~~ off-site data.

Upper air data for Quillayute, Washington, were used as it is the closest station to the site with upper air data. Data not available on-site, such as relative humidity, and any other missing data, were obtained from other nearby sites such as Bellingham, Vancouver Airport, or Seattle.

6.3.4 ISC-~~PrimeST3~~ Receptor Grid

The comprehensive receptor grid developed for the ISC-~~PrimeST3~~ dispersion modeling includes hypothetical receptors placed on both flat and elevated terrain, where appropriate. The grid is designed to allow for the simultaneous evaluation of the impacts of all CT/HRSG stacks, the diesel generator, the firewater pump, and the cooling tower. UTM coordinates were used throughout the ISC-~~PrimeST3~~ modeling. The receptor grid consists of receptors at the following locations.

- Around the property fence line in 50 meter increments,
- Fine grids of 50-meter-spaced receptors extending to approximately 1 kilometer from the property line and 100-meter-spaced receptors extending to approximately 2 kilometers from the site property line,
- Medium grids of 250-meter-spaced receptors extending to approximately 4 kilometers from the site property line and 500-meter-spaced receptors extending to approximately 8 kilometers from the site property line, and
- A coarse grid of 1,000-meter-spaced receptors that extends to approximately 12 kilometers from the site property line.

Receptor elevations used in the ISC-~~PrimeST3~~ modeling analyses were interpolated from Digital Elevation Model (DEM) data obtained from the U.S. Geological Survey (USGS). The DEM data consist of arrays of regularly spaced elevations and correspond to the 1:24,000 scale topographic quadrangle map series. The array elevations are at 30-meter intervals and the elevation at each ISC-~~PrimeST3~~ receptor was interpolated using the BEEST software to determine elevations at the defined 50-meter, 100-meter, 250-meter, 500-meter, and 1,000-meter receptor intervals. Data obtained from the DEM files were checked for completeness and spot-checked for accuracy against elevations on corresponding USGS 1:24,000 scale topographical quadrangle maps. No missing or erroneous data from the DEM files were found.

6.3.5 ISC-~~Prime~~^{ST3} Modeling Scenarios

Since combustion turbines exhibit some variation in emission rate and exhaust flow depending on the ambient temperature, emissions and flow information were provided by the turbine vendors for ambient temperatures of 5°F, 50°F, and 85°F. These temperatures represent operations on a cold day, an average day, and a hot day, respectively and were determined from a temperature distribution from the five-year on-site meteorological data set. It is appropriate to model the 5°F turbine operating parameters only during the colder seasons of the year. It is ~~similarly also~~ not appropriate to model the 85°F conditions during the colder winter months. However, for this application, each temperature/~~turbine load~~ scenario was modeled for the entire year to find the potential maximum ambient impacts ~~for short-term averaging times~~. Realistically, for the annual averaging period, the 50°F scenarios are more representative of annual impacts than are the 5°F and 85°F cases. ~~were used.~~

The CTs were modeled at all of the operating scenarios listed in Table 6-2 ~~for short-term averaging times~~. Stack flow and temperature for all of each of the modeled scenarios and facility equipment are also listed in Table 6-2.

Criteria pollutant emission rates, as modeled, are listed in Table 6-3. CT emissions were modeled assuming that they operate full time (i.e., 8,760 hours per year for both duct burning and non-duct burning cases). For short-term averaging times, it is assumed that the turbines ~~all sources~~ operate full time (i.e. 24 hours in a 24-hour period).

The emission rates for TAPs are listed in Table 4-5 and are based on the worst-case scenarios emissions for VOC and PM₁₀ emissions. TAP impacts were modeled in the same manner as the criteria pollutants calculated by modeling unit emissions (1 lb/hr) and multiplying by the corresponding emission rates for each TAP.

Since the three CT/HRSG stacks are physically identical and the permit application considers all three CT/HRSGs to be in operation simultaneously for 24 hours per day, 7 days per week, and 52 weeks per year, the CT stacks were conservatively modeled as one stack location chosen to represent all three stacks. This minimizes computer processing requirements, but can result in slight overestimates of ground-level pollutant concentrations.

Auxiliary equipment (diesel engines and cooling tower) was modeled using the stack flow, temperature data, and criteria pollutant emissions listed on Table 6-3. Maximum hourly criteria pollutant emission rates are listed in Table 4-2 and the toxics emission rates are listed in Table 4-4.

The emergency generator and the firewater pump are each assumed to be operated up to 250 hours per year and up to 2 hours per week. Annual emissions were calculated by multiplying the peak hourly emission rates by the 250 operating hours per year. For the PM₁₀, SO₂, and CO short-term averaging periods (24-hours or less), the peak hourly diesel engine emissions are used and adjusted in the model to account for the proposed 2 hour per day operations. This is accomplished by using the capability of the ISC-Prime model to distribute and “factor” source emissions by the hour of the day.

The testing of the emergency generator and the firewater pump is expected to take place no more than once each week during the day between the hours of 09:00 a.m. (0900) and 4:00 p.m. (1600). To simulate the impact of the emissions from the diesel engines, the peak hourly emissions for the diesel engines are turned on during the 0900 through 1600 period (modeled hours 10 through 16) for each day of the year by using the “hour of day” capability of the ISC-Prime dispersion model. The multiplication “factors” applied to the peak hourly emissions are 0.09785, 0.2857, 0.2857, 0.6667, and 1.0 for the 24-hour, 8-hour, 3-hour, and 1-hour averaging periods, respectively (e.g., annual = $250/7/365$; 24-hour and 8-hour = $2/7$; 3-hour = $2/3$). For other hours of the day, the “factor” was zero, which turns off the emissions during that hour.

Since the emergency generator and the firewater pump could also be operated over any given 24-hour period during an emergency, the modeling analyses included modeling these sources individually as if the equipment were operated continuously over the 24-hour period. During an emergency, the CTs and cooling tower would not be operating.

6.4 The cooling tower is assumed to be operating full time when the CTs are in operation. Therefore, the cooling tower PM_{10} emissions were modeled using the continuous peak hourly emission rate. The cooling tower will consist of 12 cells. For dispersion modeling purposes, the 12 cooling tower cells were modeled as 3 individual cells, each with one-third of the total hourly cooling tower PM_{10} emissions.

6.4 CalPuff Modeling

Most steady-state Gaussian plume models are not considered accurate for predicting ambient pollutant impacts at receptors that are greater than 50 kilometers in distance from the emissions source. USEPA’s *Guideline On Air Quality Models* (Guidelines) (USEPA, 2000) lists the CalPuff model as a preferred model for evaluating impacts beyond 50 kilometers. As all of the Class I areas are more than 50 kilometers from the proposed project, CalPuff was used for the Class I SIL analysis and AQRV analysis.

CalPuff is a multi-layer, multi-species, non-steady-state puff dispersion model that simulates the effects of time and space-varying meteorological conditions on pollutant transport, transformation, and removal. CalPuff version 5.4, provided by Earth Tech Inc., was used.

6.4.1 CalPuff Model Options

Modeling was performed in accordance with the guidelines set forth in the *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* and the *Federal Land Manager’s Air Quality Related Values Workgroup (FLAG) Phase I Report*. Guideline options were used such as Gaussian distribution, partial-puff-height adjustment, stack tip downwash, Pasquill-Gifford dispersion coefficients and partial plume penetration of an elevated inversion.

The primary pollutants to impact haze are ammonium sulfate and ammonium nitrate. These compounds are formed through atmospheric reactions involving NO_2 and SO_2 , which are products of combustion. NO_2 absorbs light (causing a brown color) and can also impact visibility, although to a lesser degree than ammonium sulfate and ammonium nitrate. In addition, PM, which is also emitted from the turbines and duct burners, can contribute to haze. CalPuff uses the MESOPUFF-II chemical transformation algorithms where the concentrations of the five previously mentioned pollutants, plus nitric acid, are tracked.

There are two user-selected input parameters that affect the MESOPUFF-II chemical transformation: ammonia and ozone concentrations. The IWAQM Phase 2 report recommends using ammonia concentration values of 0.5 ppb for forests, 1.0 ppb for arid lands, and 10 ppb for grasslands. Since the land use in the study domain is mixed, 10 ppb is a conservative value to assure that the conversion of NO_x to ammonium sulfate is not ammonia limited. ~~However, on the advice of the FLM, 17 ppb was used to account for suspected higher ammonia levels in the area. An initial ozone concentration of 28 ppb was used as a conservative value.~~

An ozone concentration of 28 ppb was suggested by officials of GVRD during our meeting and teleconference of July 12, 2001. To verify this figure, ambient ozone data was obtained from GVRD and analyzed. Data from the nearest two ozone monitoring stations to the Cogeneration Project site at Surrey and Langley from 1999 to 2001 was obtained and analyzed. The results of this analysis showed:

- The maximum annual average O_3 concentration at these monitoring stations was approximately 20 ppb.
- The maximum 24-hour O_3 concentration measured at either of these locations was 48 ppb and the 98th percentile concentration was 39 ppb.
- The maximum 24-hour O_3 concentration measured on the day with the maximum calculated visibility change within the time period studied was 15 ppb.

Since these monitoring stations are within the Vancouver urban area, and ozone concentrations are expected to decrease with distance away from the urban areas, the 28 ppb O_3 concentration is a conservative, but reasonable value for background ozone concentrations in the areas between the project site and the Class I areas.

For Class I SIL modeling, the chemical transformation option was not used. NO_x , PM_{10} , and SO_2 are the only pollutants that need to be modeled for Class I areas.

6.4.2 Buildings and Other Structures (Aerodynamic Downwash)

The building downwash information used in the ISCST3 modeling was also used with all CalPuff modeling analyses. BPIP output was input directly into the CalPuff model.

6.4.3 CalPuff Meteorological Data

One year of MM5 data from April of 1998 through February of 1999 was used in conjunction with data from 25 National Weather Service (NWS) surface meteorological stations to develop the meteorological field using CalMet, which is part of the CalPuff modeling system. The MM5 data is numerical meteorological forecast generated by the Department of Atmospheric Sciences at the University of Washington using the Penn State/NCAR mesoscale model version 3.4 (MM5 v3.4). This data was obtained by AirPermits.com from the Department of Ecology who had obtained it from the University of Washington.

The CalMet meteorological processor combines information from multiple surface and upper air meteorological stations as well as topography and land use data to compile a three-dimensional meteorological field. Based on recommendations found in the IWAQM Phase 2 report, the meteorological domain, which is equal to the CalPuff modeling domain, was determined by extending 50 kilometers beyond the outer receptors and sources considered in the analysis. This resulted in a grid that is approximately 504 kilometers by 408 kilometers. A 12 kilometer by 12 kilometer resolution was used for the domain.

Upper air data and precipitation data were obtained from the MM5 data. Pseudo upper air meteorological stations and precipitation stations were created at intervals of 96 kilometers and 32-48 kilometers, respectively. This resulted in the use of 20 upper air stations and 63 precipitation stations in the development of the meteorological file.

Terrain data and land use data needed for the CalMet program were obtained from USGS digital data from the USGS website at <http://edc.usgs.gov/geodata/>. 1:250,000 data were used. The data were reformatted into a form suitable for use by CalMet utility programs that are available with the CalPuff modeling system.

6.4.4 CalPuff Receptors

Lambert Conformal Coordinates (LCC) were used as the grid system throughout the CalPuff modeling since it is more appropriate for a modeling area of this size and the MM5 data are in these coordinates. A five-2.5 kilometer spaced discrete receptor grid within each Class I area was used to determine concentrations and deposition values. Receptors with closer spacing were determined to be unnecessary due to the large distances from the source to the receptors.

6.4.5 CalPuff Modeling Scenarios

One case from each scenario group (Cases 1AA to 1CC, 2A to 2C, and 6A to 6C) were used in the Class I modeling. The 100 percent load at 5°F for each scenario group (Cases 1AA, 2A, and 6A) have the highest emissions and were, therefore, used in the Class I modeling. All of the cases considered are shown in Table 6-2.

The source emissions used in the visibility and deposition modeling differs from those used in the SIL analysis. Ammonium sulfate is double counted in the SIL analysis as SO₂ and PM₁₀ as a conservative assumption. In the CalPuff model, ammonium sulfate can be input as

sulfates. Since the visibility calculation includes impacts from sulfates and particulates, it is not necessary to include the ammonium sulfate in both categories. PM₁₀ emissions are therefore, modeled without the addition of atmospheric conversion of sulfur to ammonium sulfate as described in Section 4. Also, since the CalPuff model performs chemical transformation of SO₂ to SO₄, only a 5% conversion was used to calculate SO₄ emissions to conservatively account for any in-stack transformation. The remaining 95% of the sulfur was modeled as SO₂. As in the PM₁₀ calculations described in Section 4, it is assumed that 20 percent of the sulfur is converted to ammonium sulfate, however, this is not added to the PM₁₀ emissions and the remaining 80 percent of the sulfur is converted to SO₂ (instead of 100 percent). The emissions, as modeled in the AQRV analysis, are presented in Table 6-3.

Similar to the ISC-PrimeST3 modeling, the three CT stacks were conservatively modeled as one stack location chosen to represent all three CT stacks.

The visibility modeling includes the reduction of emissions from three utility boilers to be decommissioned due to the construction and operation of the power plant. The visibility modeling, including the reduction in emissions from the utility boilers, is presented to show a more realistic analysis of the effects on visibility for this Project.

Since CalPuff cannot accept negative emissions (reductions in emissions) from any source, the reduction in emissions expected from the curtailment or elimination of operations at the Refinery utility boilers was modeled in a separate CalPuff model run. The model results for the utility boilers were subtracted from those of the power plant using the CalSum utility program, which is included with the CalPuff modeling package. The utility boiler emissions are presented in Table 6-4.

6.4.6 Post Processing

Post processing of the CalPuff output was performed using the CalPost program. Post processing is necessary to process raw CalPuff output files and produce tabulations that summarize the results. For visibility modeling, CalPost calculates the extinction coefficients based on the concentrations and relative humidity calculated in CalPuff. CalPost model runs are performed for all three scenarios for each pollutant in the SIL analysis, visibility, and deposition for nitrogen and sulfur. Visibility and deposition are also calculated for each Class I area.

Extinction coefficients used in the CalPost model were obtained from the FLAG report. PM₁₀ is classified as a combination of 50.17% elemental carbon, 16.742% organic carbon, and 33.341% soil. The combined extinction coefficient is 6.03.8 (Wien, 2002).

Before subjecting the deposition model runs to the CalPost postprocessor, the deposition results from CalPuff were input into the Postutil program that is included in the CalPuff modeling package. Postutil combines each wet and dry deposition component into total nitrogen and sulfur deposition.

7 IMPACT ANALYSIS

The results of the air quality impact analyses performed for the proposed project are presented in this section and are summarized in a series of tables. In accordance with the requirements, all modeling input and output files will be submitted in an electronic format. Summary tables of the dispersion modeling modeled emissions and results are presented in Appendix [E-6F](#). A sample ISC-[PrimeST3](#) output file is included in Appendix [E-7G](#). CalPuff output files are very large and are not presented in this report. Sample CalMet and CalPuff input files and CalPost output files are included in Appendix [E-8H](#). ISC-[PrimeST3](#) and CalPuff input and output files are included on compact disk.

7.1 Significant Impact Level Modeling Analysis

The results of the dispersion modeling analyses for Class I and Class II pollutant concentrations for each air emission modeled are presented in Tables 7-1 and 7-2 (for Class I and Class II areas, respectively). As can be clearly seen from the table, no Class I or Class II SIL is expected to be exceeded under the “worst-case” emission scenarios. No further dispersion modeling is required to demonstrate compliance with air quality standards and PSD increments.

7.2 PSD Increments

The projected concentrations of all air emissions with an associated PSD increment are below their respective significant impact levels, therefore, a PSD increment consumption analysis is not required.

7.3 Ambient Air Quality Standards

The projected concentrations of all air emissions with an associated ambient air quality standard are below their respective SILs. Therefore, a dispersion modeling analysis, taking into account other existing or permitted sources of air emissions, is not required for this analysis to demonstrate that the projected facility emissions will not have an adverse effect on the air quality levels in the region or the maintenance of the ambient air quality standards or the public health and welfare.

7.4 Toxic Air Pollutants (TAPs)

Based on the emission inventory for non-carcinogenic and carcinogenic TAPs (see Section 4.3), 17 TAPs are anticipated to be emitted in a quantity in excess of the screening emission levels presented in WAC 173-460. Therefore, a comparison to Ecology-published

ASILs is required for those compounds. The results of the dispersion modeling for toxic compounds are summarized in Table 7-3.

From the dispersion modeling results, it is evident that none of the toxic compounds expected to be emitted will result in any of the respective annual or 24-hour ASILs being exceeded.

7.5 Visibility

The results of the dispersion modeling for visibility impacts are summarized in Table 7-4. The maximum visibility change, when subtracting the emissions for the three utility boilers, as described in Section 6.4.5, is 2.34-50 percent. Since this is less than the regulatory significance level of 5 percent and is not perceptible, the proposed Project and associated utility boiler decommissioning will not have a significant impact on the visibility of the surrounding Class I areas.

If the reductions in emissions associated with decommissioning the boilers are not considered, the CalPuff modeling results show that the maximum change in visibility in a Class I area from the power plant alone is 6.08-85 percent. The maximum visibility change is modeled in Olympic National Park. Only oneFour days in the modeled period waswere above 5 percent in all of the modeledthis Class I areas. (6.58, 6.42, and 5.98 are the next highest days) and an additional day in Glacier Peak Wilderness Area was modeled at 5.26 percent. As mentioned above, the maximum visibility change is modeled at less than 5 percent, however, when the emissions for the three utility boilers to be decommissioned are subtracted.

7.6 Deposition

Emissions from the proposed project will not result in significant sulfur and nitrogen deposition in the surrounding Class I areas considered in this analysis. The CalPuff modeling results show that sulfur and nitrogen deposition will be below the significance level of 5 g/ha/yr for both sulfur and nitrogen. Maximum sulfur deposition is 0.7385 g/ha/yr and the maximum nitrogen deposition is 0.6794 g/ha/yr. The results of the dispersion modeling for deposition impacts are summarized in Table 7-4.

7.7 Other Impacts

7.7.1 Impact On Non-Attainment Areas

No state of Washington-designated non-attainment area exists within 50 kilometers of the project site. As all projected “worst-case” concentrations are anticipated to be below the SILs, no adverse impact on any non-attainment area is expected.

7.7.2 Soils and Vegetation

Based on the results of the dispersion modeling analyses, facility emissions are expected to have a negligible effect on soils and vegetation. The Project will combust only low-sulfur natural gas fuel, thus minimizing the emission of sulfur compounds. For emissions of NO_x (assuming full conversion to NO₂), potential plant damage could begin to occur with 24-hour NO₂ concentrations of 15 to 50 parts per billion (ppb) (USFS 1992). From the modeling results, the maximum annual concentration of NO₂ is below 1.0 microgram per cubic meter ($\mu\text{g}/\text{m}^3$) (about 1.1 ppb). The potential impact on local agriculture is expected to be negligible.

7.7.3 Ambient Air Quality Monitoring

Based on the results of the dispersion modeling analyses, preconstruction ambient air quality monitoring for this project is not required. All projected concentrations are well below the “*de-minimus*” levels presented in Table 3-6.

7.7.4 Odor

The operation of the proposed facility is not expected to create any nuisance odor conditions.

Anhydrous ammonia will be used in the selective catalytic reduction (SCR) system for the control of NO_x emissions. Ammonia is commonly perceived as having an odor (e.g., household cleaners, etc.). However, in the quantity to be released through the stack (the SCR system uses ammonia as a reaction agent and is present in the HRSG exhaust gas flow), an ammonia odor should not be detectable. In fact, the dispersion modeling conducted for ammonia at a rate of ~~40.5~~ ppm (a maximum of ~~34.8~~ 13.2 lbs/hour per turbine and about ~~173181~~ tons/year total) from the exhaust stacks indicate that the public exposure to ammonia (approximately ~~17.7~~ 5.8 $\mu\text{g}/\text{m}^3$ or 0.00825 ppm) will be well below the accepted range where an ammonia odor could be detected (5 to 53 ppm) (Clayton, 1993). Relative to the public health exposure of ammonia, the maximum projected ground-level impact of the ammonia emissions is about ~~18.6~~ percent of the 100 $\mu\text{g}/\text{m}^3$ 24-hour health-based standard identified in WAC 173-460. The storage and the potential for an accidental release of ammonia is not part of the PSD program.

No other odors are anticipated from the cogeneration facility. No odors are typically associated with the combustion of natural gas in CTs.

7.7.5 Population Growth

The project site is within an area already zoned for Heavy Impact Industrial Use. During the anticipated 2-year construction period, the peak construction work force could be about 670 people. For daily operation and maintenance of the facility, about 30 full time staff may be required. Air quality and visibility impacts due to growth-related activities associated with the proposed facility are expected to be negligible.

7.7.6 Fugitive and Secondary Emissions

A very low amount of secondary emissions are expected during construction at the site and installation of the combustion turbines with a small potential increase in fugitive dust and exhaust from motor vehicles and other construction equipment. Fugitive emissions after installation is complete will also be negligible. Air quality impacts from any potential sources of fugitive or secondary emissions are expected to be negligible.

8 SUMMARY AND CONCLUSIONS

Based on information presented in this air permit application, the following are demonstrated:

- All applicable provisions and requirements of the PSD program are satisfied.
- All applicable provisions and requirements of WAC 173-400 are satisfied.
- The proposed emission controls represent BACT for each applicable pollutant given the technical feasibility, energy, environmental, and economic considerations.
- Criteria and toxic emissions from the proposed project will not cause any significant air quality impacts under any potential operating scenario. All projected impacts will be below the federal and state Class I and Class II pollutant concentration SILs and ASILs for toxic emissions.
- National and State ambient air quality standards will not be exceeded.
- The applicable Class I and Class II PSD increments will not be exceeded.
- No perceptible effects on soils and vegetation are expected.
- The Project will not adversely affect population growth in the area.
- The Air Quality Related Values in PSD Class I areas will be protected.

The assessment of the air quality impacts of the proposed facility is conducted in accordance with the requirements set forth in the USEPA Guidelines and the Ecology requirements. The results of the dispersion modeling indicate that the proposed installation and operation of the combustion turbines will have less than significant (inconsequential) impacts on the local and regional air quality levels.

Based on the results of the impact analysis, it is concluded that the Project will not pose an adverse threat to the maintenance of the local or regional ambient air quality standards, the health and welfare of the general public, or the maintenance of the Air Quality Related Values in the sensitive PSD Class I areas. Therefore, the preparation and issuance of the air permit should proceed.

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LIMITATIONS

The services described in this report were performed consistent with generally accepted professional consulting principles and practices. No other warranty, express or implied, is made. These services were performed consistent with our agreement with our client. This report is solely for the use and information of our client unless otherwise noted. Any reliance on this report by a third party is at such party's sole risk.

Opinions and recommendations contained in this report apply to conditions existing when services were performed and are intended only for the client, purposes, locations, time frames, and project parameters indicated. We are not responsible for the impacts of any changes in environmental standards, practices, or regulations subsequent to performance of services. We do not warrant the accuracy of information supplied by others, or the use of segregated portions of this report.

TABLES

Table 3-1
Emission Standards and Other Limitations

Source	Pollutant	Emission or Other Limit	Regulatory Citation
Combustion turbines	NO _x	103 ppmvd at 50 °F and full load operation	40 CFR 60.332(a)(1). NSPS for stationary combustion turbines with a heat input greater than 100 mmBtu/hr
	SO ₂	150 ppmvd at 15% O ₂ and/or 0.8% by weight sulfur in fuel	40 CFR 60.333(a), (b). NSPS for stationary combustion turbines with a heat input greater than 10 mmBtu/hr
Duct Burners	NO _x	0.20 lb/mmBtu	40 CFR 60.44b(a)(4)(i)
All Fuel Burning Sources	Opacity	Shall not exceed 20% for more than three minutes in any one hour.	WAC 173-400-040(1). General standards for all sources.

Table 3-2
Significant Emission Rates

Pollutant	Emission Rate (tons/year)
Carbon Monoxide (CO)	100
Nitrogen Oxides (NO _x)	40
Sulfur Dioxide (SO ₂)	40
Particulate Matter (PM)	25
Fine Particulate Matter (PM ₁₀)	15
Volatile Organic Compounds (VOC)	40
Lead	0.6
Asbestos ^a	0.007
Beryllium ^a	0.0004
Mercury ^a	0.1
Vinyl Chloride ^a	1
Fluorides	3
Sulfuric Acid Mist	7
Hydrogen Sulfide (H ₂ S) ^a	10
Total Reduced Sulfur (Including H ₂ S)	10
Reduced Sulfur Compounds (Including H ₂ S)	10
NOTE: Source: WAC 173-400-030(67) and 40 CFR 52.21(b)(23)(I)	
^a Exempted from federal PSD review under the Clean Air Act Amendments (CAAA) of 1990. These pollutants are now regulated as Hazardous Air Pollutants pursuant to Section 112(g) (Title III) of the CAAA. However, they are retained in the Washington rules (WAC 173-460).	

Table 3-3
PSD Increments

Pollutant and Averaging Period	Class I Increment ($\mu\text{g}/\text{m}^3$)	Class II Increment ($\mu\text{g}/\text{m}^3$)
<u>Sulfur Dioxide</u>		
Annual Arithmetic Average	2	20
24-hour	5	91
3-hour	25	512
<u>Particulate Matter</u>		
Annual Geometric Average	5	19
24-hour	10	37
<u>Nitrogen Dioxide</u>		
Annual Arithmetic Average	2.5	25
NOTE: Source: 40 CFR 52.21(c).		

Table 3-4**Ambient Air Quality Standards
(REVISED, APRIL 2003)**

Pollutant	Averaging Period ^a	National Standards (µg/m ³)		Washington (µg/m ³)
		Primary	Secondary	
Sulfur Dioxide	Annual Average	80	---	53
	24-hour Average	365	---	260
	3-hour Average	---	1,300	---
	1-hour Average	---	---	1,065
Total Suspended Particulates	Annual Geometric Mean	---	---	60
	24-hour Average	---	---	150
PM ₁₀	Annual Average	50	50	50
	24-hour Average	150	150	150
PM _{2.5} ¹	Annual Average	15	15	---
	24-hour Average	65	65	---
Carbon Monoxide	8-hour Average	10,000	10,000	10,000
	1-hour Average	40,000	40,000	40,000
Ozone	1-hour Average	235	235	235
	8-hour Average ¹	157	157	---
Nitrogen Dioxide	Annual Average	100	100	100
Lead	Quarterly Average	1.5	1.5	1.5
1. As of April, 2003, the PM _{2.5} and ozone 8-hour standards are not being enforced until a nation-wide assessment of which areas are in attainment and non-attainment is made.				

Table 3-5
Significant Impact Levels

Pollutant	Averaging Time				
	Annual	24-hour	8-hour	3-hour	1-hour
Class I					
SO ₂	0.1 µg/m ³	0.2 µg/m ³	---	1.0 µg/m ³	---
PM ₁₀	0.2 µg/m ³	0.3 µg/m ³	---	---	---
NO ₂	0.1 µg/m ³	---	---	---	---
Class II					
SO ₂	1.0 µg/m ³	5.0 µg/m ³	---	25 µg/m ³	---
PM ₁₀	1.0 µg/m ³	5.0 µg/m ³	---	---	---
NO ₂	1.0 µg/m ³	---	---	---	---
CO	---	---	500 µg/m ³	---	2,000 µg/m ³
Source: Robert Bachman, USFS, Memo on 1/22/2002 for Class I and WAC 173-400-113(3) for Class II					

Table 3-6***DeMinimus* Monitoring Concentrations**

Pollutant	Concentration (µg/m3)
Carbon Monoxide (CO)	575
Nitrogen Oxides (NO _x)	14
Sulfur Dioxide (SO ₂)	13
Total Suspended Particulate (TSP)	10
Fine Particulate Matter (PM ₁₀)	10
Ozone (O ₃)	None
Lead	0.1
Beryllium	0.001
Mercury	0.25
Vinyl Chloride	15
Fluorides	0.25
Sulfuric Acid Mist	7
Hydrogen Sulfide (H ₂ S)	0.2
Total Reduced Sulfur (Including H ₂ S)	10
Reduced Sulfur Compounds (Including H ₂ S)	10
NOTE: Source: 40 CFR 52.21(b)(23)(i)	

Table 4-1**Hourly Criteria Pollutant Emission Rates - Turbines
(REVISED, APRIL 2003)**

Operating Scenario	Operating Parameters			Hourly Emissions (lb/hr)						
	Inlet Temperature (°F)	Load (%)	Duct Burning (mmBtu /hr)	NO _x	CO (2 ppm annual average)	CO (5 ppm short-term average)	VOC	PM ₁₀	SO ₂ (0.8 gr S annual average)	SO ₂ (1.6 gr S short-term average)
1AA	5	100	0	17.5	8.5	21.3	2.2	18.7	4.2	8.3
1AB	50	100	0	16.3	8.0	20.0	2.0	18.6	3.9	7.7
1AC	85	100	0	15.0	7.3	18.3	1.9	18.5	3.5	7.1
1BA	5	75	0	14.1	6.8	17.0	1.7	18.4	3.4	6.7
1BB	50	75	0	13.1	6.4	16.0	1.6	18.3	3.1	6.3
1BC	85	75	0	12.2	5.9	14.8	1.5	18.2	2.9	5.8
1CA	5	50	0	11.0	5.4	13.5	1.4	18.1	2.7	5.3
1CB	50	50	0	10.4	5.1	12.8	1.3	18.0	2.5	5.0
1CC	85	50	0	9.6	4.7	11.8	1.3	18.0	2.3	4.7
2A	5	100	28.3	17.9	8.7	21.8	2.4	19.2	4.2	8.4
2B	50	100	28.3	16.7	8.1	20.4	2.2	19.1	3.9	7.9
2C	85	100	28.3	15.3	7.5	18.7	2.1	19.0	3.6	7.2
6A	5	100	105	18.7	9.1	22.8	3.0	20.6	4.4	8.8
6B	50	100	105	17.5	8.5	21.3	2.8	20.4	4.1	8.3
6C	85	100	105	16.1	7.9	19.6	2.7	20.3	3.8	7.6

Table 4-2**Hourly Criteria Pollutant Emission Rates - Auxiliary Equipment
(NEW)**

Operating Unit	Hourly Emissions (lb/hr)				
	NO _x	CO	VOC	PM ₁₀	SO ₂
Diesel Generator	27.5	6.9	1.3	0.7	0.80
Firewater Pump	3.33	0.17	0.14	0.05	0.105
Cooling Tower	0	0	0	1.63	0

Table 4-3**Criteria Pollutant Potential Annual Emission Rates
(REVISED, APRIL 2003)**

Operating Scenario	Annual Emissions (tons/yr)					
	Hours per year	NO _x	CO	VOC	PM ₁₀	SO ₂
Case 6B	7,960	209.1	101.8	33.8	244.0	49.3
Case 1CB	300	4.7	2.3	0.6	8.1	1.1
Hot Start	100	12.8	35.6	5.9	1.5	0.4
Shutdown	100	2.9	17.1	2.0	0.8	0.2
Offline	300	0	0	0	0	0
Total Turbines	8,760	229.4	156.8	42.2	254.4	50.9
Auxiliary Equipment						
Emergency Generator	250	3.4	0.9	0.16	0.09	0.0995
Firewater Pump	250	0.42	0.021	0.018	0.006	0.0131
Cooling Tower	8,760	0	0	0	7.1	0
Total		233.3	157.7	42.3	261.6	51.0
Totals may not equal sum of individual components due to rounding.						

Table 4-4

**Toxic Emissions that Require Modeling
(REVISED, APRIL 2003)**

Toxic Compound	Emission Rate for 3 CTs (lbs/hr)	Emission Rate for Emergency Generator (lbs/hr)	Emission Rate for Firewater Pump (lbs/hr)	Total Annual Emissions (lbs/yr)	Maximum Hourly Emissions (lbs/hr)	SQER (lbs/yr)	SQER (lbs/hr)	ASIL ($\mu\text{g}/\text{m}^3$)	Class A or B Toxic Compound	
Acetaldehyde	0.0210	0.00039	0.001553	184.8	0.023	50	NA	0.45	A	annual
Acrolein	0.0373	0.000121	0.0001872	327.1	0.038	175	0.02	0.02	B	24-hr
Ammonia ¹	39.5	0	0	346,247	39.5	17,500	2.0	100	B	24-hr
Benzene	0.0705	0.01192	0.001889	621.4	0.084	20	NA	0.12	A	annual
1,3-Butadiene	0.0025	0	0.0000791	22.0	0.0026	0.5	NA	0.0036	A	annual
Formaldehyde	0.5876	0.00121	0.00239	5,148	0.59	20	NA	0.077	A	annual
PAH	0.0129	0.00326	0.000034	113.5	0.016	NA	NA	0.00048	A	annual
Arsenic	0.000052	0.00371	0.000265	1.5	0.00403	NA	NA	0.00023	A	annual
Beryllium	0.000003	0	0	0.03	0.000003	NA	NA	0.00042	A	annual
Cadmium	0.000287	0.000350	0.0000250	2.6	0.00066	NA	NA	0.00056	A	annual
Chromium	0.0259	0.003710	0.000265	227.6	0.030	175	0.02	1.7	B	24-hr
Cobalt	0.0255	0	0	223.6	0.026	175	0.02	0.33	B	24-hr
Copper ¹	0.0257	0	0	225.3	0.026	175	0.02	0.3	B	24-hr
Manganese	0.0256	0	0	224.2	0.026	175	0.02	0.4	B	24-hr
Nickel	0.0260	0.000350	0.0000250	228.3	0.026	0.5	NA	0.0021	A	annual
Zinc ¹	0.0331	0.003850	0.000275	290.7	0.037	175	0.02	7	B	24-hr
Sulfuric Acid ¹	8.1	0.2437	0.0321	71,040	8.38	175	0.02	3.3	B	24-hr
NOTES: 1. Not an USEPA Classified HAP SQER = Small Quantity Emission Rate ASIL = Acceptable Source Impact Level The maximum hourly toxics emissions are calculated from Case 6A. These represent worst-case toxic emissions.										

Table 5-1
Capital Cost Estimation Factors

CAPITAL COSTS	
<u>DIRECT COSTS</u>	
1. Purchased	
a. Basic Equipment Cost (BEC)	1a
b. Auxiliary Equipment	0.35 x (1a)
c. Instrumentation	0.10 x (1a)
d. Structural Support	0.10 x (1a)
e. Taxes & Freight	0.08 x (1a+1b+1c+1d)
2. Direct Installation	0.30 x (1a+1b+1c+1d+1e)
Total Direct Cost (TDC)	1+2
<u>INDIRECT COSTS</u>	
3. Indirect Installation Cost	
a. Engineering and Supervision	0.10 x (TDC)
b. Construction and Field Expenses	0.10 x (TDC)
c. Construction Fee	0.10 x (TDC)
d. Contingencies	0.10 x (TDC)
4. Other Indirect	
a. Startup and Testing	0.10 x (TDC)
b. Working Capital	30 days O&M cost
Total Indirect Cost (TIC)	3+4
TOTAL CAPITAL COST (TCC)	TDC+TIC
ANNUALIZED COSTS	
<u>DIRECT OPERATING COSTS:</u>	
1. Operating Labor	\$35 per man-hour
2. Supervisory	0.15 x (1)
3. Maintenance	0.03 x (TDC)
4. Replacement	
a. Catalyst	0.65 x BEC or provided by manufacturer
b. Other	0.10 x BEC
5. Ammonia	\$300/ton aqueous
<u>INDIRECT OPERATING COSTS</u>	
6. Overhead	0.30 x (1+2) + 0.12 x (3)
7. Property Tax	0.01 x TCC
8. Insurance	0.01 x TCC
9. Administration	0.02 x TCC
10. Capital	CRF ^a x TCC (0.142 x TCC)
ANNUALIZED COST	Total of Costs 1 through 11
Source of cost factors: OAQPS Cost Control Manual (USEPA, January 1995)	
A CRF = Capital Recovery Factor (see text)	

Table 5-2

**Cost Associated with SCONox – Complete System Purchase
(REVISED, APRIL 2003)**

CAPITAL COSTS	
DIRECT COSTS	
1. Purchased Equipment	
a. Basic Equipment (A)	\$10,148,000
b. Auxiliary Equipment (0.35 A)	0
c. Instrumentation (0.10 A)	0
d. Structural Support (0.10 A)	1,014,800
e. Taxes & Freight (0.08 (a + b))	811,800
Total Purchased Equipment Cost (B)	\$11,974,600
2. Direct Installation (0.30 B)	3,592,400
Total Direct Cost (TDC) (1+2)	\$15,567,000
INDIRECT COSTS	
3. Indirect Installation Cost	
a. Engineering and Supervision (0.10 TDC)	\$1,556,700
b. Construction and Field Expenses (0.10 TDC)	1,556,700
c. Construction Fee (0.05 TDC)	778,400
d. Contingencies (0.03 TDC)	467,000
4. Other Indirect Costs	
a. Startup and Testing (0.01 TDC)	155,700
b. Working Capital (30 days O&M cost)	233,200
Total Indirect Cost (TIC) (3+4):	\$4,747,700
Capital cost for demineralized water plant	\$33,600
TOTAL CAPITAL COST (TCC) (1+2+3+4)	\$20,348,300
ANNUALIZED COSTS	
DIRECT OPERATING COSTS:	
1. Operating Labor (C) (\$35/man-hr)	\$76,650
2. Supervisory Labor (0.15 C)	11,500
3. Maintenance (0.03 TDC)	467,000
4. Replacement Parts	
a. Catalyst replacement (\$4,301,700/5 yrs)	860,300
b. Other (0.1 A)	1,014,800
5. Utilities	
a. Output penalty (0.2% of MW output, \$42/MWh)	132,500
b. Demineralized water (8.4 GPM)	6,600
c. Natural gas for regeneration (1800 scf/hr)	13,100
6. Unscheduled outage (5 days/yr, \$10/MWh)	216,000
7. Disposal Costs (included in catalyst replacement cost)	0
INDIRECT OPERATING COSTS	
8. Overhead (0.3 (1+2) + 0.12 (3))	\$82,500
9. Property Tax (0.01 TCC)	203,500
10. Insurance (0.01 TCC)	203,500
11. Administration (0.02 TCC)	407,000
12. Capital Recovery (0.142 TCC)	2,889,500
ANNUALIZED COST (\$/yr)	\$6,584,450
NO_x Controlled (ton/yr)	195
Cost per ton of NO_x controlled (\$/ton)	\$33,800
CO Controlled (ton/yr)	154.3
Cost per ton of CO controlled (\$/ton)	\$42,700
NO_x, CO, and VOC CONTROLLED (ton/yr)	364
COST PER TON OF POLLUTANTS CONTROLLED (\$/ton)	\$18,100

Table 5-3

**Costs Associated with SCONox
Mechanical System Purchase/Catalyst Lease
(REVISED, APRIL 2003)**

CAPITAL COSTS	
DIRECT COSTS	
1. Purchased Equipment	
a. Basic Equipment (A)	\$5,846,300
b. Auxiliary Equipment (0.35 A)	0
c. Instrumentation (0.10 A)	0
d. Structural Support (0.10 A)	584,600
e. Taxes & Freight (0.08 (a + b))	467,700
Total Purchased Equipment Cost (B)	\$6,898,600
2. Direct Installation (0.30 B)	2,069,600
Total Direct Cost (TDC) (1+2)	\$8,968,200
INDIRECT COSTS	
3. Indirect Installation Cost	
a. Engineering and Supervision (0.10 TDC)	\$896,800
b. Construction and Field Expenses (0.10 TDC)	896,800
c. Construction Fee (0.05 TDC)	448,400
d. Contingencies (0.03 TDC)	269,000
4. Other Indirect Costs	
a. Startup and Testing (0.01 TDC)	89,700
b. Working Capital (30 days O&M cost)	188,200
Total Indirect Cost (TIC) (3+4):	\$2,788,900
<i>Capital cost for demineralized water plant</i>	<i>\$33,600</i>
TOTAL CAPITAL COST (TCC) (1+2+3+4)	\$11,790,700
ANNUALIZED COSTS	
DIRECT OPERATING COSTS:	
1. Operating Labor (C) (\$35/man-hr)	\$76,650
2. Supervisory Labor (0.15 C)	11,500
3. Maintenance (0.03 TDC)	269,000
4. Replacement Parts	
a. Catalyst lease cost (\$79,035/month)	948,400
b. Other (0.1 A)	584,600
5. Utilities	
a. Output penalty (0.2% of MW output, \$42/MWh)	132,500
b. Demineralized water (8.4 GPM)	6,600
c. Natural gas for regeneration (1800 scf/hr)	13,100
6. Unscheduled outage (5 days/yr, \$10/MWh)	216,000
7. Disposal Costs (included in catalyst replacement cost)	0
INDIRECT OPERATING COSTS	
8. Overhead (0.3 (1+2) + 0.12 (3))	\$58,700
9. Property Tax (0.01 TCC)	117,900
10. Insurance (0.01 TCC)	117,900
11. Administration (0.02 TCC)	235,800
12. Capital Recovery (0.142 TCC)	1,674,300
ANNUALIZED COST (\$/yr)	\$4,462,950
NO_x Controlled (ton/yr)	195
Cost per ton of NO_x controlled (\$/ton)	\$22,900
CO Controlled (ton/yr)	154.3
Cost per ton of CO controlled (\$/ton)	\$28,900

Table 5-4

**Costs Associated with SCR and Oxidation Catalysts for NO_x, CO, and VOC Control
(REVISED, APRIL 2003)**

ANNUALIZED COST (\$/yr)	\$3,226,600
NO_x, CO AND VOC CONTROLLED (ton/yr)	311
COST PER TON OF POLLUTANTS CONTROLLED (\$/ton)	\$10,400

Table 5-5
Costs Associated with SCR for NO_x Control
(REVISED, APRIL 2003)

CAPITAL COSTS	
DIRECT COSTS	
1. Purchased Equipment	
a. Basic Equipment (A)	\$2,291,900
b. Auxiliary Equipment (0.35 A)	0
c. Instrumentation (0.10 A)	0
d. Structural Support (0.10 A)	229,200
e. Taxes & Freight (0.08 (a + b))	183,400
Total Purchased Equipment Cost (B)	\$2,704,500
2. Direct Installation (0.30 B)	811,400
Total Direct Cost (TDC) (1+2)	\$3,515,900
INDIRECT COSTS	
3. Indirect Installation Cost	
a. Engineering and Supervision (0.10 TDC)	\$351,600
b. Construction and Field Expenses (0.10 TDC)	351,600
c. Construction Fee (0.05 TDC)	175,800
d. Contingencies (0.03 TDC)	105,500
4. Other Indirect Costs	
a. Startup and Testing (0.01 TDC)	35,200
b. Working Capital (30 days O&M cost)	68,800
Total Indirect Cost (TIC) (3+4):	\$1,088,500
TOTAL CAPITAL COST (TCC) (1+2+3+4)	\$4,604,400
ANNUALIZED COSTS	
DIRECT OPERATING COSTS:	
1. Operating Labor (C) (\$35/man-hr)	\$76,650
2. Supervisory Labor (0.15 C)	11,500
3. Maintenance (0.03 TDC)	105,500
4. Replacement Parts	
a. Catalyst (609,000/3 yrs)	203,000
b. Other (0.1 A)	229,200
5. Utilities	
a. Output penalty (0.2% of MW output, \$42/MWh)	132,500
6. Ammonia Cost (\$300/ton)	66,800
7. Disposal Costs (included in catalyst replacement cost)	0
INDIRECT OPERATING COSTS	
8. Overhead (0.3 (1+2) + 0.12 (3))	\$39,100
9. Property Tax (0.01 TCC)	46,000
10. Insurance (0.01 TCC)	46,000
11. Administration (0.02 TCC)	92,100
12. Capital Recovery (0.142 TCC)	653,800
ANNUALIZED COST (\$/yr)	\$1,702,150
NO_x Controlled (ton/yr)	181
Cost Per Ton of NO_x Controlled (\$/ton)	\$9,400

Table 5-6

**Costs Associated with Catalytic Oxidation for CO Control
(REVISED, APRIL 2003)**

CAPITAL COSTS	
DIRECT COSTS	
1. Purchased Equipment	
a. Basic Equipment (A)	\$2,162,900
b. Auxiliary Equipment (0.35 A)	0
c. Instrumentation (0.10 A)	0
d. Structural Support (0.10 A)	216,300
e. Taxes & Freight (0.08 (a + b))	173,000
Total Purchased Equipment Cost (B)	\$2,552,200
2. Direct Installation (0.30 B)	765,700
Total Direct Cost (TDC) (1+2)	\$3,317,900
INDIRECT COSTS	
3. Indirect Installation Cost	
a. Engineering and Supervision (0.10 TDC)	\$331,800
b. Construction and Field Expenses (0.10 TDC)	331,800
c. Construction Fee (0.05 TDC)	165,900
d. Contingencies (0.03 TDC)	99,500
4. Other Indirect Costs	
a. Startup and Testing (0.01 TDC)	33,200
b. Working Capital (30 days O&M cost)	58,000
Total Indirect Cost (TIC) (3+4):	\$1,020,200
TOTAL CAPITAL COST (TCC) (1+2+3+4)	\$4,338,100
ANNUALIZED COSTS	
DIRECT OPERATING COSTS:	
1. Operating Labor (C) (\$35/man-hr)	\$76,650
2. Supervisory Labor (0.15 C)	11,500
3. Maintenance (0.03 TDC)	99,500
4. Replacement Parts	
a. Catalyst (480,000/3 yrs)	160,000
b. Other (0.1 A)	216,300
5. Utilities	
a. Output penalty (0.2% of MW output, \$42/MWh)	132,500
6. Disposal Costs (included in catalyst replacement cost)	0
INDIRECT OPERATING COSTS	
7. Overhead (0.3 (1+2) + 0.12 (3))	\$38,400
8. Property Tax (0.01 TCC)	43,400
9. Insurance (0.01 TCC)	43,400
10. Administration (0.02 TCC)	86,800
11. Capital Recovery (0.142 TCC)	616,000
ANNUALIZED COST (\$/yr)	\$1,524,450
CO Controlled (ton/yr)	119
Cost Per Ton of CO Controlled (\$/ton)	\$12,800

Table 5-7

**Costs Associated with Wet Scrubber for SO₂ and H₂SO₄ Control
(REVISED, APRIL 2003)**

CAPITAL COSTS	
DIRECT COSTS	
1. Purchased Equipment	
a. Basic Equipment (A)	\$5,263,700
b. Auxiliary Equipment (0.35 A)	1,842,300
c. Instrumentation (0.10 A)	526,400
d. Structural Support (0.10 A)	526,400
e. Taxes & Freight (0.08 (a + b))	568,500
Total Purchased Equipment Cost (B)	\$8,727,300
2. Direct Installation (0.30 B)	2,618,200
Total Direct Cost (TDC) (1+2)	\$11,345,500
INDIRECT COSTS	
3. Indirect Installation Cost	
a. Engineering and Supervision (0.10 TDC)	\$1,134,600
b. Construction and Field Expenses (0.10 TDC)	1,134,600
c. Construction Fee (0.05 TDC)	567,300
d. Contingencies (0.03 TDC)	340,400
4. Other Indirect Costs	
a. Startup and Testing (0.01 TDC)	113,500
b. Working Capital (30 days O&M cost)	112,800
Total Indirect Cost (TIC) (3+4):	\$3,403,200
TOTAL CAPITAL COST (TCC) (1+2+3+4)	\$14,748,700
ANNUALIZED COSTS	
DIRECT OPERATING COSTS:	
1. Operating Labor (C) (\$35/man-hr)	\$76,650
2. Supervisory Labor (0.15 C)	11,500
3. Maintenance (0.03 TDC)	340,400
4. Replacement Parts	
b. Other (0.1 A)	526,400
5. Electricity	175,300
6. Soda Ash	223,000
7. Wastewater Treatment	1,689,300
INDIRECT OPERATING COSTS	
7. Overhead (0.3 (1+2) + 0.12 (3))	\$67,300
8. Property Tax (0.01 TCC)	147,500
9. Insurance (0.01 TCC)	147,500
10. Administration (0.02 TCC)	295,000
11. Capital Recovery (0.142 TCC)	2,094,300
ANNUALIZED COST (\$/yr)	\$5,794,150
SO₂ AND H₂SO₄ Controlled (ton/yr)	19.5
Cost Per Ton Of Pollutants Controlled (\$/ton)	\$297,100

Table 5-8**Summary of BACT
(REVISED, APRIL 2003)**

Pollutant	Control Technology	Cost (\$/ton pollutant removed)
NO _x	SCR	9,400
	SCONox – complete purchase	33,800
	SCONox – lease	22,900
CO	CO Oxidation Catalyst	12,800
	SCONox – complete purchase	42,800
	SCONox – lease	29,000
VOC	Good combustion control in combination with CO oxidation catalyst	0
NO _x , CO, VOC total	SCR and oxidation catalyst	10,400
NO _x , CO, VOC total	SCONox (complete system purchase)	18,100
PM ₁₀	Low sulfur/low ash fuel and good combustion control	0
SO ₂ and H ₂ SO ₄	Low sulfur/low ash fuel and good combustion control	0
	Wet Scrubber	297,100
Toxic Air Pollutants	Low sulfur/low ash fuel and good combustion control in combination with CO oxidation catalyst	0
Control technologies in bold are those that have been selected as BACT.		

Table 5-9

**Requested Maximum Emission Limits – Per CT/HRSG System
(REVISED, APRIL 2003)**

Loads/ Temperatures	NO _x	CO	VOC	PM ₁₀	SO ₂ ¹	Ammonia
50 – 100% loads with or without duct burners firing NG /any ambient inlet temperature	2.5 ppm annual rolling average	2.0 ppm annual rolling average 5.0 ppm 1-hour average	3.0 lb/hr 24-hour average	20.6 lb/hr 24-hour average	8.8 lb/hr 24-hour average	5 ppm 24-hour average
Notes: 1. SO2 emissions based on 1.6 gr S.						

Table 6-1
Stack and Building Dimensions
(REVISED, APRIL 2003)

Source or Structure	Height (ft)	Length or Diameter (ft)	Width (ft)
CT/HRSG stacks	150	19 ¹	NA
Emergency Generator	11.7	0.67 ¹	NA
Firewater Pump	11.7	0.5 ¹	NA
Cooling Tower Cells	75	30.0 ¹	NA
HRSGs	95	110	30
Cooling Tower	60	330	110
Switchgear Building	30	70	50
Steam Turbine Enclosure	50	190	90
Water Treatment Building	30	135	80
Admin/Warehouse Building	30	220	65
Emergency Generator Building	11	20	10
Firewater Pumphouse Building	11	300	13
Fire/Raw Water Tank	40	42 ¹	NA
NOTE:			
1. Diameter			
2. All dimensions are approximate until final design.			

Table 6-2**Operating Load, Temperature and Flow Rate Conditions
(REVISED, APRIL 2003)**

Case	Ambient Temp. (°F)	Turbine Load (%)	Duct Burner (MMBtu/hr)	Volume Flow (1000 acfm)	Velocity (ft/sec)	Temp (°F)
1AA	5	100	0	1,109	65.2	195
1AB	50	100	0	1,029	60.5	195
1AC	85	100	0	949	55.8	195
1BA	5	75	0	855	50.3	190
1BB	50	75	0	811	47.7	190
1BC	85	75	0	772	45.4	190
1CA	5	50	0	681	40.0	180
1CB	50	50	0	660	38.8	180
1CC	85	50	0	638	37.5	180
2A	5	100	28.3	1,149	67.5	190
2B	50	100	28.3	1,066	62.7	190
2C	85	100	28.3	983	57.8	190
6A	5	100	105	1,133	66.6	180
6B	50	100	105	1,052	61.8	180
6C	85	100	105	970	57.0	180
Emer. Gen.	All	All	NA	12.745	270	899
Fire Pump	All	All	NA	1.404	119	840
Cooling Tower	All	All	NA	1,144	29.6	90

Table 6-3
Modeled Emission Rates
(REVISED, APRIL 2003)

Case	Ambient Temp °F	Gas Turbine Load %	Duct Burning MMBtu/hr	Concentration Modeling					Visibility Modeling		
				NO _x ¹	CO	PM ₁₀	SO ₂ ²	SO ₂ ³	PM ₁₀ ⁴	SO ₂ ⁵	SO ₄ ⁶
				lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
1AA	5	100	0	52.5	63.8	56.1	12.5	24.9	51.0	11.8	0.9
1AB	50	100	0	48.9	60.0	55.8	11.6	23.2	51.0	11.0	0.9
1AC	85	100	0	45.0	54.8	55.4	10.6	21.3	51.0	10.1	0.8
1BA	5	75	0	42.3	51.0	55.2	10.1	20.2	51.0	9.6	0.8
1BB	50	75	0	39.3	48.0	54.9	9.4	18.9	51.0	9.0	0.7
1BC	85	75	0	36.6	44.3	54.6	8.8	17.5	51.0	8.3	0.7
1CA	5	50	0	33.0	40.5	54.3	8.0	16.0	51.0	7.6	0.6
1CB	50	50	0	31.2	38.3	54.1	7.5	15.1	51.0	7.2	0.6
1CC	85	50	0	28.8	35.3	53.9	7.0	14.0	51.0	6.6	0.5
2A	5	100	28.3	53.8	65.5	57.6	12.7	25.3	52.4	12.0	1.0
2B	50	100	28.3	50.2	61.1	57.3	11.8	23.7	52.4	11.2	0.9
2C	85	100	28.3	46.0	56.1	56.9	10.9	21.7	52.4	10.3	0.8
6A	5	100	105	56.1	68.4	61.7	13.2	26.5	56.2	12.6	1.0
6B	50	100	105	52.5	64.0	61.3	12.4	24.8	56.2	11.8	0.9
6C	85	100	105	48.4	58.9	60.9	11.4	22.8	56.2	10.8	0.9
Generator ^{7,8}	All	All	NA	27.5	6.9	0.7	0.796	0.796	0.058	0.0019	0.00015
Fire Pump ^{7,8}	All	All	NA	3.3	0.17	0.05	0.105	0.105	0.0042	0.00025	0.000020
Cooling Tower	All	All	NA	NA	NA	1.6	NA	NA	1.6	0.0	0.0

NOTES:

Emissions are for 3 turbines.

1. NO_x values are used for concentration and visibility modeling.
2. SO₂ is calculated using 0.8 gr S/100scf natural gas (annual modeling)
3. SO₂ is calculated using 1.6 gr S/100scf natural gas (short-term modeling)
4. PM₁₀ emissions for CalPuff visibility modeling do not include ammonium sulfate emissions that are included in the ISCST3 modeling.
5. SO₂ emissions for CalPuff visibility modeling are calculated by subtracting the 5% sulfur converted to SO₄.
6. SO₄ emissions for CalPuff visibility modeling are calculated by assuming a 5% conversion from SO₂ and multiplying by the ratio of molecular weights (96/64).
7. Emission rates modeled are adjusted from these values to specific averaging period based on 2 hours per day operation.
8. Emission rates based on the use of 0.05% S fuel.

Table 6-4

Boiler Emission Rates for Visibility Modeling

Operating Unit	Units	NO _x	CO	VOC	PM ₁₀	SO ₂
Annual Boiler Emissions	Tons/yr	184.0	11.0	0.0	3.0	26.0
Hourly Boiler Emissions	lb/hr	42.0	2.5	0.0	0.7	5.9
NOTE: Annual emissions are based on year 2000 operations. Hourly emissions calculation based on full time operation of 8,760 hours per year. SO ₂ emissions were modeled at 4.7 lb/hr, which is 80% of the above value. The remaining emissions were modeled as SO ₄ at a level of 1.8 lb/hr.						

Table 7-1

**Significant Impact Level Modeling Analysis Results - Class II Areas
(REVISED, APRIL 2003)**

Pollutant	Maximum Predicted Concentration ($\mu\text{g}/\text{m}^3$) ¹					SIL ($\mu\text{g}/\text{m}^3$) ²
	Annual	24-hr	8-hr	3-hr	1-hr	
NO _x	0.60 ³					1
CO			50.4 ⁴		81.4 ⁴	500/2,000
PM ₁₀	0.25 ³	4.3				1/5
SO ₂	0.03 ³	4.3 ⁴		8.4 ⁴		1/5/25
1. Highest of all cases for 1995, 1996, 1998, 1999, 2000. 2. Significant Impact Level (SIL) for criteria pollutants. 3. Based on annual average ambient temperature of 50°F. 4. Due to emergency use of diesel generator.						

Table 7-2

**Significant Impact Level Modeling Analysis Results - Class I Areas
(REVISED, APRIL 2003)**

Pollutant	Maximum Predicted Concentration ($\mu\text{g}/\text{m}^3$) ¹					SIL ($\mu\text{g}/\text{m}^3$) ²
	Annual	24-hr	8-hr	3-hr	1-hr	
NO _x	0.0053					0.1
PM ₁₀	0.0054	0.087				0.2/0.3
SO ₂	0.001	0.021		0.048		0.1/0.2/1
CO ³						
1. Highest of all cases for 1995, 1996, 1998, 1999, 2000. 2. Significant Impact Level (SIL). 3. Not modeled in Class I Areas.						

Table 7-3**Significant Impact Level Modeling Analysis Results - Toxic Compounds
(REVISED, APRIL 2003)**

Pollutant	Maximum Predicted Concentration ($\mu\text{g}/\text{m}^3$)		ASIL ($\mu\text{g}/\text{m}^3$) ³	ASIL Exceeded (Yes/No)
	Annual ¹	24-hr ²		
Acetaldehyde	0.00014	NA	0.45	No
Acrolein	NA	0.0027	0.02	No
Ammonia	NA	2.76	100	No
Benzene	0.00032	NA	0.12	No
1,3-Butadiene	0.00001	NA	0.0036	No
Formaldehyde	0.00237	NA	0.077	No
PAH	0.00007	NA	0.00048	No
Arsenic	0.00007	NA	0.00023	No
Beryllium	< 0.00001	NA	0.00042	No
Cadmium	0.00001	NA	0.00056	No
Chromium	NA	0.0024	1.7	No
Cobalt	NA	0.0018	0.33	No
Copper	NA	0.0018	0.3	No
Manganese	NA	0.0018	0.4	No
Nickel	0.00011	NA	0.0021	No
Zinc	NA	0.0025	7	No
Sulfuric Acid	NA	0.57	3.3	No
1. Highest of annual cases 1AB, 1BB, 1CB, 2B, 6B (at 50°F). 2. Highest of all cases for 1995, 1996, 1998, 1999, 2000. 3. Acceptable source impact levels (ASIL).				

Table 7-4**AQRV Modeling Analysis Results
(REVISED, APRIL 2003)**

Operating Scenario	Class I area	N Deposition	S Deposition	Maximum Visibility Change	Number of days over 5%	Maximum Visibility Change including Boiler Emissions Reductions	Number of days over 5%
		(g/ha/yr)	(g/ha/yr)	(%)		(%)	
Case 1AA	Olympic National Park	0.09	0.11	5.5	1	1.6	0
	North Cascades National Park	0.44	0.31	2.5	0	1.4	0
	Alpine Lakes Wilderness Area	0.56	0.68	3.8	0	1.9	0
	Glacier Peak Wilderness Area	0.42	0.32	4.1	0	1.8	0
	Pasayten Wilderness Area	0.23	0.13	1.7	0	1.0	0
	Mt. Baker Wilderness Area	0.63	0.56	4.0	0	2.2	0
Case 2A	Olympic National Park	0.09	0.11	5.6	1	1.7	0
	North Cascades National Park	0.45	0.31	2.5	0	1.4	0
	Alpine Lakes Wilderness Area	0.57	0.70	3.9	0	2.0	0
	Glacier Peak Wilderness Area	0.42	0.32	4.2	0	1.9	0
	Pasayten Wilderness Area	0.23	0.13	1.7	0	1.1	0
	Mt. Baker Wilderness Area	0.64	0.57	4.0	0	2.3	0
Case 6A	Olympic National Park	0.09	0.12	6.0	1	1.9	0
	North Cascades National Park	0.47	0.32	2.6	0	1.5	0
	Alpine Lakes Wilderness Area	0.60	0.73	4.1	0	2.3	0
	Glacier Peak Wilderness Area	0.44	0.34	4.4	0	2.1	0
	Pasayten Wilderness Area	0.24	0.14	1.8	0	1.2	0
	Mt. Baker Wilderness Area	0.67	0.60	4.1	0	2.3	0
Case 6A – Maximum Sulfur in summer	All 6 Class I areas	--	--	1.0	0	--	---
Maximum		0.67	0.73	6.0	1	2.3	0
NOTES: Significance level for visibility is 5%. Significance level for deposition is 5 g/ha/yr. Case 6A is a maximum possible operation case. Case 2A is a normal operation case. From May 15 to September 15, the fuel sulfur content may rise from 0.8 gr/100 scf to 1.6 gr/100 scf. Case 6A was modeled during this period with this sulfur content.							

APPENDICES

APPENDIX [AE-1](#)

**VENDOR PROVIDED COMBUSTION TURBINE EMISSIONS
INFORMATION**

APPENDIX [BE-2](#)

CRITERIA AND TOXIC POLLUTANT EMISSION SUMMARY

Emissions Factors

APPENDIX [CE-3](#)

BACT/LAER CLEARINGHOUSE LISTINGS

APPENDIX [DE-4](#)

COSTS ASSOCIATED WITH EMISSION CONTROLS

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DISPERSION MODELING PROTOCOLS

APPENDIX [FE-6](#)

MODELED EMISSIONS AND RESULTS

APPENDIX [GE-7](#)
SAMPLE ISCST3 OUTPUT

|

APPENDIX HE-8

SAMPLE CALPUFF INPUT AND OUTPUT FILES

Figures

Figure 2-1
Regional Map

Figure 2-2
Vicinity Map

Figure 2-3

Site Plan

FORMS